Fuel Capability Demonstration Test Protocol
for the
JEA Large-Scale CFB Combustion Demonstration Project

APPENDIX A TO THE DOE PHASE III TEST PLAN

Submitted to
U.S. DEPARTMENT OF ENERGY
National Energy Technology Laboratory (NETL)
Pittsburgh, Pennsylvania 15236
Cooperative Agreement No.
DE-FC21-90MC27403

March 1, 2004

Prepared by:

JEA

Building Community

TABLE OF CONTENTS

TABLES

FIGURES

1.0 INTRODUCTION

The agreement between the US Department of Energy (DOE) and JEA covering DOE participation in the Northside Unit 2 project requires JEA to demonstrate the ability of the unit to utilize a variety of different fuels. Therefore, it is necessary for JEA to demonstrate this capability through a series of tests. Unless otherwise indicated, the term “unit” refers to the combination of the circulating fluidized bed (CFB) boiler and the air quality control system (AQCS). The AQCS consists of a lime-based spray dryer absorber (SDA) and a pulse jet fabric filter (PJFF).

This document (hereinafter the “Test Procedure") defines JEA’s Fuel Capability Demonstration Test (hereinafter the “Test") for the JEA Large-Scale CFB Combustion Demonstration Project. The objective of the Test is to demonstrate the commercial viability of the CFB and AQCS technology specified under the agreement between JEA and the DOE utilizing a specific variety of solid fuels.

The test program will document the ability of the unit to utilize the fuels/fuel blends in a cost effective and environmentally responsible manner. Fuel flexibility will be quantified by measuring the following parameters:

- Boiler efficiency
- CFB boiler sulfur capture
- AQCS sulfur and particulate capture
- Flue gas emissions (measured in the stack)
    - Particulate matter (PM)
    - Oxides of nitrogen (NO_x)
    - Sulfur dioxide (SO_2)
    - Carbon monoxide (CO)
    - Carbon dioxide (CO_2)
    - Volatile organic carbon (VOC)
    - Ammonia (NH_3)
    - Lead (Pb)
    - Mercury (Hg)
    - Fluorine (F)
    - Dioxin (Pittsburgh #8 coal only)
    - Furan Dioxin (Pittsburgh #8 coal only)
- Stack opacity

2.0 BOILER DESIGN PARAMETERS

2.1 Feedwater and Steam Conditions

Table 1, shown below, describes the steam and feedwater conditions expected during the execution of the Test. Any deviation from these conditions observed during the Test will be identified and the impact described.

Table 1 **- REFERENCE FEEDWATER AND STEAM CONDITIONS**

Main Steam (Turbine Inlet)	**Maximum-Continuous Rating (MCR)**
Flow (lb/hr)	1,993,591
Pressure (psig)	2,500
Temperature (°F)	1,000
Reheat Steam (Turbine Inlet)	
Flow (lb/hr)	1,773,263
Pressure (psia)	547.7
Temperature (°F)	1,000
Reheat Steam (HP Turbine Exhaust)	
Flow (lb/hr)	1,773,263
Pressure (psia)	608.6
Enthalpy (Btu/lb)	1304.5
Feedwater to Economizer	
Temperature (°F)	487.5

2.2 Performance Fuel Specifications

2.2.1 Fuel Composition

Fuel flexibility testing shall be performed in four distinct test periods while burning four different fuel/fuel blends. The design analysis for the fuel/fuel blends to be examined during the operational test periods is as shown in Table 2 below. Fuel blend ratios are on a percent mass basis. Complete analysis is included in Attachment C.

Table 2 **- ULTIMATE ANALYSIS OF PERFORMANCE FUEL (AS-RECEIVED)**

	Pittsburgh 8	80/20 Blend Petroleum Coke/ Pittsburgh 8	50/50 Blend Pet Coke/ Pittsburgh 8	Illinois 6
Carbon %	68.6	76.92	73.8	64.48
Hydrogen %	4.6	3.8	4.1	4.40
Sulfur %	3.3	6.02	5	2.71
Nitrogen %	1.3	1.06	1.15	1.24
Chlorine %	0.09	0.02	0.05	0.15
Oxygen %	4.11	1.06	2.20	7.34
Ash %	12.8	2.88	6.6	8.57
Moisture %	5.2	8.24	7.1	11.11
HHV (Btu/lb)	12,690	13,738	13,345	11,603

2.2.2 Fuel Size Distribution

There shall be no performance adjustment for fuel size, but the as-fired material shall be within the specified design range (see Attachment A). The size distribution shall be based on dry sieve analysis in accordance with ASTM D 4749.

2.3 Performance Limestone Specifications

2.3.1 Limestone Composition

The Limestone to be utilized during the execution of the Test is expected to be in accordance with the following table and as shown in Attachment C. Any deviation will be identified and the impact of the deviation described in the subsequent Test Report.

Table 3 **- REFERENCE LIMESTONE COMPOSITION**

Characteristic	% by Weight.	Design Range
$CaCO_3$	92.0	85.0 – 99.0
$MgCO_3$	3.0	0.2 – 5.0
Inerts	4.0	Max = 15.0
Total Moisture*	1.0	Max = 10.0**
* Includes inherent, surface and residual moisture ** 10% is the maximum as received moisture content in the limestone – it is dried to a design value of 1% moisture in the limestone preparation system prior to injection into the boiler		

2.3.2 Limestone Size Distribution

There shall be no performance adjustment for limestone size, but the limestone injected into the boiler shall be compared with the specified design range (See Attachment B). The size distribution shall be based on dry sieve analysis in accordance with ASTM D 4749.

2.4 Performance Lime Specifications

2.4.1 Lime Composition

The Lime to be utilized during the execution of the Test is expected to be in accordance with the following table. Any deviation will be identified and the impact of the deviation described in the subsequent Test Report.

Table 4 **- REFERENCE LIME COMPOSITION**

Characteristic	% by Weight.	Design Range
CaO	85	85 to 90
MgO and inerts	15	10 to 15

2.5 Ambient Conditions

Correction of Test results for deviations of ambient air conditions from the design values will apply only to the extent of the deviation of the measured ambient temperature versus the design conditions.

3.0 PERFORMANCE TEST DESIGN POINTS

The following performance design points were based on firing Performance Fuel and injecting Performance Limestone. For the purposes of this fuel capability demonstration test, the performance of the unit with respect to each of these design points shall be measured. Acceptable bands for Measurement Uncertainty (MU) ranges also apply at times as covered later in the text and in Attachment E.

The Fuel Capability Demonstration Tests shall consist of the following tests:

Table 5 **- TEST CHARACTERISTICS**

TEST#	LOAD	FUEL	TEST PERIOD	TESTED
1 A, B, C, & D	100% MCR	Per Section 2.2	4 hours	Capacity Boiler Efficiency Emissions (NO_x, SO_2, CO, & Particulate) Steam Temperature (SH & RH)
2 A, B, C, & D	100% MCR	Per Section 2.2	4 hours	Same as test #1 (2nd day)
3 A, B, C, & D	80% MCR	Per Section 2.2	4 hour	Main Steam Temperature Reheat Steam Temperature Emissions
4 A, B, C, & D	60% MCR	Per Section 2.2	4 hour	Main Steam Temperature Reheat Steam Temperature Emissions
5 A, B, C, & D	40% MCR	Per Section 2.2	4 hour	Main Steam Temperature Reheat Steam Temperature Emissions
6 A, B, C & D	Minimum Stable Load	Per Section 2.2	4 hour	Reference data only

Tests A, B, C, & D are in reference to the fuels being tested. Each of the four fuels listed in Section 2.2 will be tested under the six test conditions listed above.

3.1 Capacity

The average heat output from the steam generator to the turbine generator (TG) during the Test shall be measured to determine the boiler maximum continuous rating (MCR) as defined later in this document. This test will be coordinated with the JEA system dispatcher in order to allow the unit to operate at its maximum rating for the duration of the initial test.

3.2 CFB Efficiency Design Point

The average efficiency of the CFB during the Test shall be measured at MCR under design operating conditions when firing each respective fuel. No heat credits shall be considered beyond adjusting ambient air temperature to design conditions.

3.3 Emissions Design Point

The Unit 2 AQCS consists of a single SDA and a multi-compartment PJFF. The SDA has sixteen independent dual-fluid atomizers. The fabric filter has eight isolatable compartments. The AQCS system also uses reagent preparation and byproduct handling subsystems. The SDA byproduct solids/fly ash (herein after referred to as fly ash) collected by the PJFF is pneumatically transferred from the PJFF hoppers to either the Unit 2 fly ash silo or the Unit 2 AQCS recycle bin. Fly ash from the recycle bin is slurried and reused as the primary reagent by the SDA spray atomizers. The reagent preparation system converts quicklime (CaO), which is delivered dry to the station, into a hydrated lime [$Ca(OH)_2$] slurry, which is fed to the atomizers as a supplemental reagent.

It is intended that during the flexibility tests, all sixteen SDA atomizers will be in service at all times; however, on-line replacement of any atomizer that fails during a test will not be sufficient cause for aborting a test. Normal on-line maintenance to all equipment will be performed during the test program. Installed spares may be used during a component failure, but may not be used to supplement normally operating equipment.

The fabric filter is designed for either on-line or off-line filter bag cleaning with one compartment out of service. Therefore, isolation of one compartment for maintenance will not be sufficient cause for aborting a test. Normal on-line maintenance of all fabric filter components will be performed during the test program. Installed spares may be used during a component failure, but may not be used to supplement normally operating equipment.

The reagent preparation subsystem, including the fly ash recycle equipment, will operate throughout the test.

The operation of the AQCS, including the amounts of lime and fly ash recycle used and filter bag cleaning, will be automatically regulated by the AQCS control system to meet the air quality permit's SO_2 emission and opacity limits.

3.3.1 NO_x / SO_2 / Particulate Emission Design Points

The following gaseous emissions shall be measured for each 4-hour interval during the Test (EPA Permit averaging period).

a. **Nitrogen oxides** (NO_x) in the flue gas are expected to be less than 0.09 lb/MMBtu HHV fuel heat input. The hourly average lb/MMbtu value reported by the Continuous Emissions Monitoring (CEM) system shall be used as the measure of NO_x in the flue gas over the course of each fuel test.

b. **Sulfur dioxide** (SO_2) in the flue gas out of the air heater is expected to be not over 0.939 lb/MMbtu when firing performance petroleum coke and not over 0.183 lb/MMBtu when firing performance coal. The SO_2 emissions from the stack during the execution of the Tests are expected to be less than 0.015 lb/MMBtu. The hourly average lb/MMbtu value reported by the CEM shall be used as the measure of SO_2 emissions for each respective fuel test.

c. **Solid particulate matter** in the flue gas at the baghouse outlet is expected to be maintained at less than 0.011 lb/MMBtu HHV fuel heat input, based on EPA Method 17 or Method 5.

3.3.2 CO Emissions Design Point

Carbon monoxide (CO) in the flue gas is expected to be less than or equal to 0.22 lb/MMBtu HHV fuel heat input at 100% MCR. This design point applies when firing Performance Coke or Performance Coal and shall be measured for each respective test.

3.3.3 SO_3 Emissions Design Point

Sulfur Trioxide (SO_3) in the flue gas is assumed to be zero. No testing will be done for SO_3. See Section 4.2.3 for rationale.

3.3.4 NH_3/ Lead/ Mercury/ Fluorine Emissions Design Points

NH_3, Lead, Mercury, and Fluorine gaseous emissions shall be measured for each 4-hour interval during the Test (EPA Permit averaging period). Quantities in the flue gas and removal efficiency expectations are unknown and will be determined by testing at the 100% load point only. Mercury sampling and analysis will be performed at the inlet to the AQCS system in addition to the sample taken at the stack. Lead, ammonia and Fluorine will be sampled only at the stack.

3.3.5 Dioxin and Furan Emissions Design Points

Dioxin and Furan gaseous emissions shall be measured for each 4-hour interval during the Test (EPA Permit averaging period) for 100% Pittsburgh 8 (Pitt 8) coal only. Quantities in the flue gas and removal efficiency expectations are unknown and will be determined by testing at the 100% load point only.

3.3.6 Opacity

The opacity shall not exceed 10% over a six minute block average.

3.4 Steam Temperature Design Point

The average steam temperatures during the Test shall be within the limits described in the following sections. The average of the readings recorded every minute shall be determined to be the Test average:

a. Main steam temperature 1000 °F +10/-0 °F at the turbine throttle valve inlet from 75 to 100% of turbine MCR and 1000 °F +/-10 °F at the turbine throttle valve inlet from 60 to 75% of turbine MCR.

b. Hot reheat steam temperature 1000 °F +10/-0 °F at the turbine intercept valve inlet from 75 to 100% of turbine MCR and 1000 °F +/-10 °F at the turbine intercept valve inlet from 60 to 75% of turbine MCR.

3.5 Calcium to Sulfur (Ca:S) Ratio Design Point

The average calcium to sulfur molar ratio during the Test is expected to not exceed 2.093 while firing the pet coke blends and 2.88 when firing coal only and injecting Performance Limestone while meeting the SO_2 emission design value.

3.6 Minimum Stable Load Demonstration

The minimum stable operating load without firing startup fuel will be demonstrated. No performance calculations or test corrections will be provided from this test. Reference data will be gathered using the plant PI data historian. This will include all of the data points shown in Table F-3. Valve isolation will not be required during this test. The operator will be allowed to take what ever actions are necessary to safely maintain a stable load on the unit with the exception of utilization of start up fuel. It is expected that this test will be demonstrated by the 40% MCR test.

4.0 FUEL DEMONSTRATION TEST CALCULATION PROCEDURES

4.1 Capacity

The capacity of the boiler shall be calculated in terms of percent of the MCR design heat output as described below. Note that this is a delivered thermal power criterion and not a temperature or pressure design point. The former parameter is covered by the Steam Temperature design point, and the latter one is set by the feedwater supply system.

4.1.1 Calculation Method and Measurement Instrumentation

$\% \ MCR_{AS\text{-}MEASURED} = 100 * ((W_{MS} *(H_{MS}\text{-}h_{FW}) + W_{RH} * (H_{HRH} - H_{CRH})) / ((1{,}993{,}591 \times (1457.111 - 470.491) + 1{,}773{,}000 \times (1521.647 - 1303.793))$

$= (W_{MS} * (H_{MS} - h_{FW}) + W_{PS} * (H_{PS} - h_{FW}) + W_{RH} * (H_{HRH} - H_{CRH})/2{,}353{,}171{,}429$

Where: H_{CRH} = Cold reheat steam enthalpy at the boiler outlet, Btu/lb*
h_{FW} = Feedwater enthalpy entering the economizer, Btu/lb
H_{HRH} = Hot reheat steam enthalpy at the boiler outlet, Btu/lb*
H_{MS} = Main steam enthalpy at the boiler outlet, Btu/lb*

W_{MS} = Main steam flow, lb/hr, = feedwater flow to CFB (QF-34-FT-501) + SH attemperation water (QF-34-FT-500), i.e. all vents, drains, blowdowns and bypasses closed

W_{RH} = Reheat steam flow, lb/hr, = Main steam flow - (TG leak-offs (TG Manufacturer's data) + extraction to top (#1) heater** + RH attemperation water (FI-0546)

* = ASME steam tables will be used in all cases to determine enthalpy values (1967 revision is referenced as the document of record).

** = Determined by heat balance, i.e. feedwater flow x enthalpy rise per lb = extraction flow x enthalpy loss per lb, all measurements using plant instrumentation except as noted later in this document.

That is,
W_{FWH} (feedwater flow at heaters) = QF-34-FT-501 (feedwater to CFB) + QF-34-FT-500 (SH attemperation) + SE-34-FT-582 (RH attemperation), and
$W_{EXTR1} = W_{FWH} * (h_{\#1OUTFW} - h_{\#1INFW}) / (H_{EXTR1} - h_{\#1DRN})$

Where:
W_{FWH} = feedwater flow at heaters
$h_{\#1OUTFW}$ = BFW enthalpy at heater #1 outlet
$h_{\#1INFW}$ = BFW enthalpy at heater #1 inlet
W_{EXTR1} = Extraction flow to heater #1
H_{EXTR1} = Enthalpy of extraction to #1 heater
$h_{\#1DRN}$ = Enthalpy of drain from #1 heater

The formula presented above ignores differences between water temperatures at the economizer inlet, superheater spray and reheat spray locations, which should be minimal since these streams all are drawn from downstream of the top heater outlet.

4.1.2 Corrections

MCR_{CORR} shall be used for Test capacity design point compliance purposes, being MCRAS-MEASURED with adjustment for deviations from design operating conditions (ref. Section 6.2.1, Attachment D and mutually agreed MU per section 6.2.4). The main steam flow calculation will be based on CFB feedwater flow measurement as described above rather than the TG first-stage shell pressure criterion for the purpose of minimizing MU.

4.1.3 Frequency, Averaging and Interpretation of Measurements

The data of Attachment F, Table F-3 shall be logged continuously for instruments tied to the DCS, and manually obtained readings shall be logged every 30 minutes or more frequently if required by the Test Manager. Samples and performance data shall be obtained as specified in the related portions of this Procedure.

$MCR_{AS\text{-}MEASURED}$ and MCR_{CORR} data points for the purpose of ultimately determining the average capacity attained during the Test shall be calculated for the Test period specified. Average readings shall be used for each parameter involved in determining the four-hour MCR data.

The individual data points recorded in this fashion will be documented by the Test Coordinator at the end of each test. A written acknowledgement of stable conditions will be signed-off by the Test Coordinator at the end of each test to acknowledge the stabilized test conditions. This documentation will then be provided to the Test Manager.

4.2 Efficiency

4.2.1 Calculation Method

The boiler efficiency calculation method utilized shall be the abbreviated heat loss method as defined by ASME Power Test Code (PTC) 4.1 (1974, reaffirmed 1991), modified to account for the heat of calcination and sulfation. The heat losses, which are included, are:

- Heat loss due to heat in dry flue gas
- Heat loss due to moisture in "as fired" fuel
- Heat loss due to moisture from the combustion of hydrogen in the fuel
- Heat loss due to unburned carbon in Bed Ash
- Heat loss due to unburned carbon in flyash
- Heat loss due to radiation
- Heat loss/gain due to calcination/sulfation
- Heat loss due to moisture in air

- Heat loss due to sensible heat in Bed Ash leaving boiler (outlet of rotary valve)
- Heat loss due to sensible heat in flyash at airheater outlet

The ASME calculation procedure has been modified slightly to account for process differences between conventional and fluidized bed boilers (i.e., limestone addition). These modifications account for difference in the dry gas quantity and additional heat loss/gain due to calcination/sulfation. The additional/modified calculation procedures to be used are described below.

4.2.2 Dry Gas Quantity

This parameter is conventionally calculated by deriving the lbs of dry gas/lb of carbon burned from measured oxygen and multiplying it by lb of carbon burned/lb of fuel fired. The resultant quantity is the lbs of dry gas per lb of fuel fired.

Two factors complicate this approach for fluidized bed boilers. First, a noticeable amount of CO_2 is evolved from the calcination of the limestone. Second, the sulfation reaction removes part of the SO_2 and O_2 from the flue gas.

To account for these factors, the following method has been derived for calculating the dry gas quantity:

$$\frac{\text{lb Dry Gas}}{\text{lb As-Fired (A.F.) Fuel}}$$

$$= C_b' * \frac{MW_{CO2}(CO_2)+MW_{O2}(O_2)+MW_{N2}(N_2)+MW_{CO}(CO)+MW_{SO2}(SO_2)}{MW_C(CO_2+CO)}$$

$$= C_b' * \frac{44.01(CO_2)+32(O_2)+28.02(N_2)+28.01(CO)+64.06(SO_2)}{12.01(CO_2+CO)}$$

Where:

CO_2, CO, O_2, N_2 and SO_2 are the volumetric concentrations (in percent) in the dry flue gas at the airheater outlet

MW_X = Molecular weight of respective elements

$$C_b' = C_b + \frac{W_l}{W_{fe}} \times C_x$$

$$C_x = \frac{MW_C(CaCO_3)}{MW_{CaCO3}} + \frac{MW_C(MgCO_3)}{MW_{MgCO3}} = \frac{\text{lb Carbon}}{\text{lb limestone}}$$

$$\frac{12.01(CaCO_3)}{100.09} + \frac{12.01(MgCO_3)}{84.32} = \frac{\text{lb Carbon}}{\text{lb limestone}}$$

W_l = Limestone feed rate (lb/hr)
W_{fe} = Fuel feed rate (lb/hr)
C_b = Pounds of carbon per pound of "as-fired" fuel
C_b' = Total equivalent carbon including limestone carbon per pound of fuel

4.2.3 Percent SO_2 Removal in CFB

Determination of the amount of SO_2 removal in the CFB is necessary for the calculation of the heat of sulfation. The process control continuous emissions analyzer located at the inlet to the AQCS equipment will provide the amount of SO_2 in the flue gas in lb/MMbtu and ppm. The amount of fuel fired can be calculated by an iterative process by using the gravimetric feeder data as the starting condition for the iteration. The amount of SO_2 formed from combustion of the fuel can be determined readily from the ultimate analysis of the fuel. During the 100% MCR tests the O_2 and SO_2 content of the flue gas at the SDA inlet will be measured by stack testing methods. This data will be used in place of plant analyzer data. With this data a correlation between O_2 and SO_2 instrumentation and stack test results will be developed and applied to the readings from the installed O_2 and SO_2 analyzers. The readings from the installed analyzers will be used with the correction factor on the 40%, 60% and 80% MCR tests

The CFB boiler capture is defined as the fraction of the total sulfur input to the boiler from the fuel that leaves the boiler as either gaseous SO_2 or SO_3. Although sulfur also leaves the CFB boiler as part of the fly ash, for purposes of these calculations, this fraction of the fuel sulfur input will be considered to have been captured in the boiler.

The SO_3 level in the flue gas leaving a CFB boiler is generally very low (2 ppmdv) because of the reaction between SO_3 and calcium in the bed reagent. In addition, when a selective non-catalytic reduction system (SNCR) is used for control of NO_x emissions, this low level of SO_3 is extremely difficult to accurately measure. The residual ammonia from the SNCR system reacts with the SO_3 to form ammonium bisulfate in the test probes. As a result of its expected low concentration and difficulty in accurate measurement, SO_3 term will be neglected in the boiler sulfur capture calculation.

The calculation procedure is as follows:

$$SO_2\text{, lb/hr from Combustion} = W_{fe}\text{ as-fired fuel} * S_f * \frac{64.06}{32.06}$$

S_f = Wt. fraction of sulfur in fuel, as-fired

SO_2, lb/hr flue gas = W_{SO2} (From CEM or Stack Test Data)

$$\text{Fractional } SO_2 \text{ Removal } (XSO_2) = 1 - \frac{W_{SO2}}{W_{fe} * S_f * \frac{64.06}{32.06}}$$

4.2.4 Heat Loss Due to Calcination/Sulfation

The limestone fed to the furnace undergoes an endothermic reaction (requires heat addition) known as calcination prior to reacting with the SO_2 in an exothermic reaction known as sulfation. The reactions involved in the calcination step can be written as follows:

Calcium Carbonate (h = 785.87 Btu/lb of $CaCO_3$)
$CaCO_{3(s)} \rightarrow CaO_{(s)} + CO_{2(g)}$

Magnesium carbonate (h = 512.61 Btu/lb of $MgCO_3$)

$$MgCO_{3(s)} \rightarrow MgO_{(s)} + CO_{2(g)}$$

The heats of reaction were calculated from standard heats of formation listed in Perry's Chemical Engineers Handbook (Sixth Edition).

The limestone calcination heat loss can, therefore, be calculated as follows:

Heat loss due to calcination, Btu/lb A.F. fuel

$$= \frac{\text{lb limestone}}{\text{lb A.F. Fuel}} * (CaCO_3 * 785.87 + MgCO_3 * 512.61)$$

Where: $CaCO_3$ = wt. fraction $CaCO_3$ in limestone
$MgCO_3$ = wt. fraction $MgCO_3$ in limestone

The lime (CaO) formed from the calcination of limestone reacts with part of the SO_2 in the flue gas to form calcium sulfate ($CaSO_4$) accompanied by an evolution of heat (exothermic reaction). The reaction can be expressed as follows:

$$CaO_{(s)} + SO_{2(g)} + \tfrac{1}{2}O_{2(g)} \rightarrow CaSO_{4(s)}$$
$$h = -1534.9 \text{ Btu/lb of } CaSO_4$$

The heat of reaction was calculated from the same data source and in the same manner as the heat of calcination stated above.

It is obvious from the above reaction that the amount of $CaSO_4$ formed is related to the amount of SO_2 removal. Therefore, the heat gain from sulfation can be calculated as:

Heat gain due to Sulfation, Btu/lb A.F. Fuel

$$= S_f * XSO_2 * \frac{MW_{CaSO4}}{MW_S} * 1534.9$$

$$= S_f * XSO_2 * \frac{136.12}{32.06} * 1534.9$$

where: S_f = Wt. fraction of sulfur in fuel, as-fired

The net heat loss due to the calcination/sulfation reaction is calculated as follows:

$$\frac{\text{Btu}}{\text{lb A.F. Fuel}} = \text{Heat Loss due to Calcination} - \text{Heat Gain due to Sulfation}$$

4.2.5 Radiation Loss

The radiation loss used in the calculation will be 0.18%, based on Figure 8 of PTC 4.1.

4.2.6 Corrections and Measurement Uncertainty Values

The efficiency as calculated above shall be termed "as-measured". Corrections for deviations from design-point operating conditions shall be applied per section 6.2.1 below, in addition to which the acceptance band shall be expanded by measurement uncertainty effects per part 6.2.4 (Attachment E).

Corrected efficiency values within this range of the design point will be deemed to demonstrate the ability to utilize the specific fuel. Corrected efficiency which falls below the range identified will be noted in the test report.

4.2.7 Frequency, Averaging and Interpretation of Measurements

Data collection and interpretation shall be the same as described in section 4.1.3 above.

4.3 Flue Gas Emissions

4.3.1 Sequence of Testing and Averaging of Readings

The CEM Certification Test has already been performed and documented. Therefore, data from the certified and calibrated CEM system shall be used for the as-tested emissions design point compliance purposes. The exception is particulate matter which will be measured using PM testing at full load and opacity on part loads. PM will be measured by EPA test methods at full load only, and related to opacity. That relationship will be used to infer PM from opacity measurements for the part load tests.

Test data shall be averaged for all parameters including opacity to produce (approximately) every-four-hours data points for Test reporting (EPA reporting period).

MU shall not apply for CEM based emissions guarantee compliance demonstrations since the certification procedure for these items includes the applicable bias and precision analyses.

Official data points shall be promptly signed-off by the Test Manager after each run. The final values for CEM measured emissions reporting purposes shall be the average of the acceptable four-hour data points accumulated during the test period.

4.3.2 Stack Emissions

a. Nitrogen Oxides

The CEMS readout will be used to demonstrate compliance with the NO_x emission design point.

b. Sulfur Oxides

The AQCS sulfur capture is a measure of SO_2 and SO_3 removal that occurs between the inlet to SDA module and the outlet of the PJFF. For the same reasons discussed above, SO_3 in the flue gas is very difficult to accurately measure. Therefore, SO_3 will be neglected in the determination of AQCS sulfur capture and the following equation will be used.

$$S\ Capture_{(AQCS)} = \frac{SO_{2(inlet)} - SO_{2(stack)}}{SO_{2(inlet)}} \times 100\%$$

Where: $S\ Capture_{(AQCS)}$ = Sulfur capture by the AQCS, %

$SO_{2(inlet)}$ = SO_2 in the AQCS inlet (lb/MBtu)

$SO_{2(stack)}$ = SO_2 in the stack (lb/MBtu)

The flue gas SO_2 content at the AQCS inlet and in the stack is continuously monitored by plant instrumentation in those locations. The existing data logging equipment continuously calculates and records SO_2 removal between these two points.

The data from the CEMS readout will be used to demonstrate compliance with the SO_2 emissions design point. Note the SO_2 measurement at the AQCS inlet does not go to the CEM; it goes directly to the DCS.

c. Carbon Monoxide

The CEMS readout will be used to demonstrate compliance with the CO emission design point.

4.3.3 Particulates Design Point

A one time test for particulate loading at the outlet of the baghouse will be done utilizing EPA Method 17 or Method 5 of Attachment A to Part 60 of the Federal Register. This particulate test shall consist of a minimum of three sampling runs. The average of these three sampling runs shall be used for determining the compliance with the particulate emissions design point. The particulate test shall be performed on any one day mutually agreed upon or concurrent with the two(2) 4-hour performance tests at MCR. PM will be measured by EPA test methods at full load only and related to opacity. That relationship will be used to infer PM from opacity measurements for the part load tests.

4.3.4 Type and Frequency of Testing

The method and frequency of data collection shall be based on the CEMS.

4.4 Steam Temperature

4.4.1 Measurement Location and Averaging of Readings

Measurements shall be taken using the following permanently installed instrumentation:

- Main steam at SH Outlet: SI-34-TE-556 & 557
- Main Steam at turbine throttle valve inlet: SJ-34-TE-509
- Hot reheat steam at Boiler Outlet: SH-34-TE-510 & 511
- Reheat steam at turbine intercept valve inlet: SJ-34-TE507

4.4.2 Measurement Uncertainty

The Measurement Uncertainty (MU) value applicable for this parameter is specified in 6.2.4.

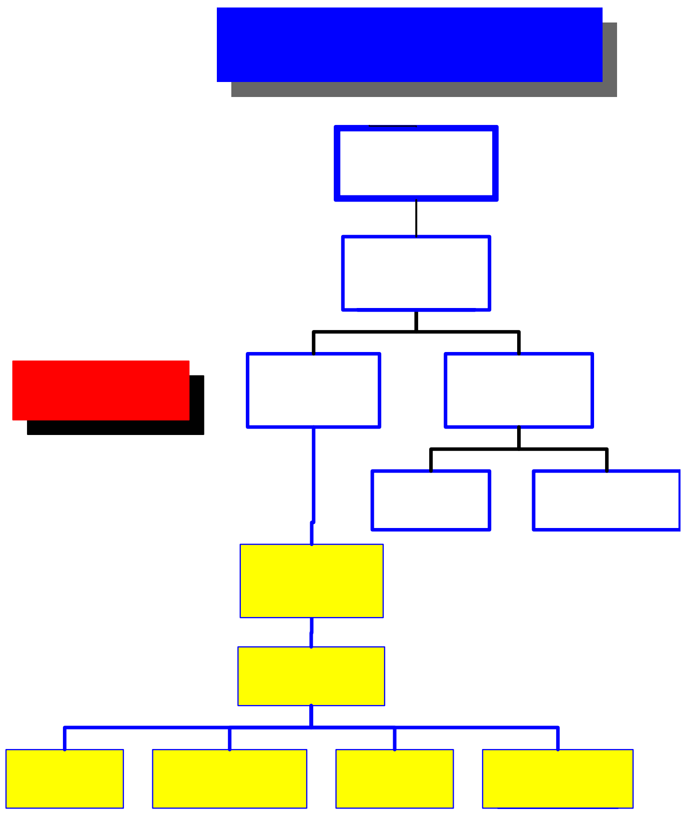
4.4.3 Frequency, Averaging and Interpretation of Measurements

Data collection and interpretation shall be the same as for the Capacity Test per section 4.1.3 above.

5.0 PERFORMANCE TEST RESPONSIBILITY

Figure 1 shown below outlines the relationship between the parties to the Test. The responsibilities of JEA and the various testing contractors are described in the following sections.

Figure 1 - TEST ORGANIZATION CHART



5.1 JEA Representatives

JEA shall be responsible for the following:

- Personnel to supervise and operate the permanently installed equipment.
- The services of an on site Test Manager.
- Permanently mounted plant instrumentation as noted herein and described in the Appendices to this document.
- PI system to access, store and retrieve operating data logged by the DCS system.
- Properly documented plant instrumentation for equipment outside the Testing Contractor's scope of supply (i.e. related to steam turbine generator set).

- Electricity, fuel, service water, fire fighting water, boiler feedwater, limestone, water treatment chemicals, lube oil and hydraulic oil and any other materials normally required to safely operate the plant.

5.2 Test Coordinator

The Test Coordinator shall be responsible for the following:

- Test Instructions, based on and including this document.
- Preparation and presentation to JEA of a daily report for the purpose of acceptance by JEA of the previous day's test data with regard to the stable conditions.
- Technical consultation regarding test conditions, requirements and execution as required by JEA.
- Creation of a critical instruments list defining the specific instruments requiring calibration by the Test Contractor in order to achieve the measurement uncertainty requirements.
- Final written Test Report.

5.3 Fuel Gas Test/Test Equipment/Sample Collection Contractors

The Fuel Gas Test/Test Equipment/Sample Collection Contractor(s) shall be responsible for the following:

- Personnel to technically coordinate with the Test Coordinator for performance of the Test. Detailed personnel assignments are not covered herein but will be developed prior to the Test.
- Special, temporary instrumentation as required per this procedure (ref. Attachment F). This includes calibration, installation, operation and removal of the temporary instrumentation at the completion of testing.
- Staff to obtain the samples and the equipment necessary to obtain the samples in accordance with the appropriate procedures described herein. This includes fuel, ash and limestone samples.
- Third-party laboratory analysis of fuel, limestone, lime, and, ash samples as described in this procedure.
- Sample containers, labels and shipping.
- Test and Lab Analysis Reports.
- Calibration of installed plant instrumentation as required to meet test uncertainty requirements.

6.0 TEST COMPLETION CRITERIA

6.1 Test Report

As measured results of the tests on each fuel/fuel blend will be compiled and submitted by the various Test Contractors, to the Test Coordinator and JEA. The as-measured test results will be provided in a draft format to allow the Test Coordinator and JEA the opportunity to review the findings and provide additional comment or input. After a period of review and comment, the Test Contractors will provide a final version of the as-measured test report.

The Test Coordinator will review the as-measured test results for completeness, apply test corrections and measurement uncertainties to the as-measured test results, and compare the corrected test results to the design values. The Test Coordinator will prepare a report summarizing the test results on each fuel/fuel blend, and submit it to JEA for review.

The Test Coordinator will provide the draft summary report to JEA within ten (10) working days of the receipt of the Flue Gas Test Contractor's final as-measured test report and laboratory results for each set of tests. A set of tests will consist of all tests associated with each fuel blend. JEA review comments will be due within ten (10) working days of receipt of the draft report. Within five (5) working days of receipt of JEA comments, the final report for that set of tests will be issued by the Test Coordinator to JEA. JEA will then be responsible for submission of the test report to DOE.

6.2 Test Corrections

The following Test Corrections apply in addition to those cited earlier. These corrections will be specifically addressed in the test report. As such they generally will not be available to review immediately after the test.

6.2.1 Corrections for Deviations from Design Operating Conditions

Test results will be corrected to design conditions for variations in operating conditions as described below.

Table 6 **- TEST CORRECTIONS**

Design Point	Correction for deviation of
Boiler Efficiency	Fuel moisture content Fuel hydrogen content Fuel Higher Heating Value Ambient air temperature Moisture in air
Main Steam Flow	Feedwater temperature to boiler
Main Steam Temp	Feedwater temperature to boiler
Hot Reheat Steam Temp	Cold Reheat Steam temp to boiler

Corrections will be applied where applicable per methods described in ASME PTC 4.1.
See Attachment D for sample calculations.

6.2.2 Duration

There shall be two (2) performance tests at 100% MCR (one test per day) each test for a period of four hours duration. Other Performance tests at 80%, 60% and 40% MCR shall be for a period of four hours at each load.

Actual time elapsed between tests will depend largely on the need to achieve stabilized operation prior to each test, and the point at which this criterion is satisfied shall be established in each case by the Test Manager. A schedule and test sequence will be developed by the Test Coordinator and provided to the Test Manager for acceptance. This test schedule will take into account each of the following.

- the duration of each test
- the required stabilization time between tests
- JEA system dispatch needs
- work schedules and relief needs of the testing staff
- the probability of extending selected tests to ensure stable operating conditions (see Section 6.2.3 below)

Based on the above, the execution of the full set of tests on each fuel/fuel blend is expected to require approximately six (6) working days, plus an additional three (3) days of operation on the test fuel prior to the start of the tests to “season” the boiler on the test fuel.

6.2.3 Upsets

Operating upsets or deviations from normal, steady-state conditions which are experienced during the Test, such as feeder pluggages, or feedwater changes (but not equipment failures, ref. section 3 above) shall be recorded and removed from the pertinent four-hour-averaged Test data. If more than two cumulative hours must be removed from the four-hour-averaged results the test shall be repeated. If the cumulative time to be removed is less than two hours the test duration shall be extended such that four hours of data are available. Tests can be extended at the Test Manager’s discretion in order to achieve acceptable test conditions.

6.2.4 Measurement Uncertainty

Based on the review of the instrumentation planned for use during the Test, the following MU values will apply for the Test:

Table 7 **- MEASUREMENT UNCERTAINTY**

Boiler Efficiency	+ / - 0.90%
Capacity (Main steam flow)	+ / - 1.90%
Main Steam Temperature	+ / - 0.50%
Reheat Steam Temperature	+ / - 0.50%

6.3 Minimum Stable Load Test

The test corrections noted above are not applicable to the Minimum Stable Load Test. Therefore the report will provide documentation of the achievement of minimum load and commentary on the specific load and conditions observed during the test.

7.0 VALVE ISOLATION

The performance test must be performed under isolated conditions as follows:

- The turbine bypass valves (12PV-509 and 12PV-507) must be closed (but available for automatic operation) as well as the bypass spray control and block valves (12F-517, 12TV-537, 12FV-540, AND 12TV-510).
- All boiler, main steam, cold reheat, hot reheat, and feedwater startup vents and drains must be closed.
- The boiler mass and continuous blowdown valves shall be closed (BK-14-694, BK-14-695, and BK-14-770).
- The boiler economizer recirculation valves shall be closed (BK-12-510 and BK-12-512).
- Reheat temperature shall be controlled by the gas biasing dampers and the reheat spray control and block valves shall be closed (SE12-FV-550 & SE12-TV-550) but available for automatic operation.
- Feedwater Heater #1 bypass valve shall be closed but available for automatic operation.
- The sootblowing system shall NOT be isolated. However, sootblowing during the test should be limited as described in section 9.2.

The remainder of the system valves shall be maintained in their normal operational valve position for the test.

A plant walk-down is recommended prior to the test to confirm the valves to be closed for isolation.

8.0 PERFORMANCE TEST PREPARATION

Appropriate preparatory tasks shall be completed prior to Test commencement. Since some of these preparations require the scheduling of services and equipment from outside firms, ample lead-time should be allowed to accomplish these requirements.

8.1 Pre-Test Activities

The following activities shall be completed prior to the Test. Unless stated to the contrary, the Test Manager will verify and document each of the following.

1. A tentative schedule will be determined by the Test Coordinator. This tentative test schedule will be reviewed and approved by the Test Manager. Once approved, this schedule will be communicated to the Test Contractor (through the Test Coordinator), any sub-contractors, JEA system dispatching, and the DOE. The tentative schedule will be completed and communicated at least two (2) calendar weeks in advance of the commencement of the Test.

2. Final Notification of the Test and Test arrangements will be provided by the Test Manager to the Test Coordinator no later than two (2) days prior to the commencement of the Test.

3. The unit shall be operated by JEA using the appropriate test fuel or fuel blend for at least seventy-two (72) hours prior to the beginning of the test stabilization period.

4. The boiler shall be operated by JEA at higher than 95% MCR load to maintain a substantially stabilized heat output and process conditions for at least five (5) hours immediately prior to the start of the Test. During this stabilization period, major operating parameters of concern as listed below shall be monitored via the plant data historian:

    - Steam flow
    - Feedwater flow
    - Fuel flow
    - Limestone flow
    - Emissions (SO_2, NO_x, CO)
    - Bed temperature
    - Cyclone inlet temperature
    - Bed pressure
    - Bed ash flow rate

    The Test Coordinator will verify the above major operating parameters are stabilized. Notification of such will be provided to the Test Manager by the Test Coordinator.

5. Verify that the data collection program (PI) for collecting test data obtained from plant instruments monitored by the plant DCS system is operating. Such verification will include the data listed in Section 9 and Attachment F.

6. As a minimum, a ten (10) day supply of the test fuel should be available prior to the Test to ensure an adequate supply of fuel for the entire Test period.

7. A minimum of a ten (10) day supply of limestone should be available prior to the Test to ensure an adequate supply for the entire Test period.

8. The Bitter Water Storage Tank should be at least 85% full to help ensure an adequate supply of demineralized water for the test period.

9. Boiler feedwater purity shall be confirmed as being within the required design limits. Prior to the start of the Test, drum blowdown shall be adjusted to achieve a boiler water solids concentration within recommended guidelines and the blowdown flow rate shall be identified.

10. A sootblowing cycle shall be completed within two hours of commencing each Test run to allow best possible compliance with the requirement that operating conditions be held constant.

11. The Bed Ash Storage Silo and Fly ash Storage Silo should be suitably low at the start of the Test so that any interruption in removal of ash does not imperil Test completion.

12. Controls tuning and/or configuration should be suspended during the Test. Maintenance activity in the areas of critical instrumentation (such as drum level transmitters) should be suspended during the Test.

13. Approximately two hours before the start of the Test the unit shall be "walked-down" by the Test Manager and Test Coordinator to ensure that the plant valving is configured according to the valve line-up requirements (ref. Section 7) and that all else is in readiness as well.

8.2 Instrumentation

Instruments to collect the Test data shall be installed, calibrated and in service.

Calibrations performed and documented at the factory or in the field will be acceptable. Any required field calibrations shall be performed using test equipment of demonstrable accuracy (i.e. traceable to the National Institute of Standards and Technology) consistent with the measurement uncertainty (MU) intervals identified in Section 6.2.4.

8.3 Provisions for Collection of Fuel, Ash, Lime, and Limestone

The testing contractor shall be responsible for collection of samples and laboratory analyses to ASME/ASTM standards on the various samples gathered during the Test. The following paragraphs describe the various sampling activities, procedures, and laboratory analyses required for the Test.

Each sample shall be collected in an appropriate container, such as double bagged or in an uncoated paint can, and sealed tightly immediately upon collection. It is very important that the samples be tightly sealed and clearly and legibly labeled. The labeling shall be as shown in Appendices G - K.

Each sampling point shall be inspected prior to the Test to ensure that the available ports provide acceptable samples. Each sampling location shall be clearly labeled prior to the Test to facilitate sample collection.

Refer to appendices as listed below for sampling log and instructions for preparing composite samples:

- Fuel Attachment L
- Limestone Attachment M
- Bed ash Attachment N
- Fly ash Attachment O
- Lime Attachment P

9.0 OPERATION, SAMPLING AND DATA COLLECTION

9.1 Initial Conditions

Prior to commencement of the Tests, all operating conditions described in Sections 1.0 through 8.0 shall have been established. In addition, necessary personnel to perform support functions during the Test shall be present and trained. These personnel will be supplied by the Testing Contractor or by JEA per Section 5 above and shall perform the following functions:

1. Collect operating data during the Test. Attachment F provides a list of parameters that are directly involved in the fuel flexibility demonstrations.

2. Collect samples of fuel, lime, limestone and ash as outlined in Section 8.3 of this document.

3. Install, calibrate and operate temporary instrumentation. Refer to Attachment F for the list of instruments.

4. Ensure that ample supplies of fuel, lime, and limestone are available to complete the Test without interruption. All fuel constituents should be within the boiler design range and as close as possible to the Performance Fuel defined in Section 2.

5. Ensure that water treatment equipment is ready to supply continuous makeup water supply for the duration of the Test.

6. Set-up the PI system to access the DCS data and printout every hour during the Test. The data printout shall be a digital table rather than a graphical display. Printouts shall be marked as an attachment and included in the test report for each fuel.

9.2 Operating Conditions

The boiler shall be operated at loads specified for each Performance Test, for the duration of the Test. Operation at less than specified load as a result of dispatcher requirements will be considered to be operation at test load and count towards successful completion of the Test, as long as the boiler and air quality control equipment operate satisfactorily through the period to supply the steam required.

The boiler will be operated at 100% MCR load during the Boiler Performance portion of the Test and at the previously-defined part-load levels for the rest of the Operational Tests. Automatic control shall be used.

Normally the sootblowers will not be operated during any of the four-hour Test runs. A full sootblowing cycle shall be completed within two hours prior to the start of each Test run. Additional sootblowing shall be done selectively on areas which indicate fouling.

Sootblowing shall be performed during a four-hour Test run if the back end temperature increases in excess of 20°F over this period as observed during pre-testing. However, the duration of sootblowing shall not extend beyond two hours for a four-hour Test run. In this case, the Test run shall be extended by two hours or a shorter interval of time as may be decided by the Test Manager.

Boiler blowdown (continuous and surface) will be off for the Test unless boiler water conductivity exceeds the maximum recommended level. During the four-hour period prior to the commencement of the Test, the continuous blowdown rate should be increased to reduce boiler water solids to as low a level as is practical. This condition will also reduce the residual treatment chemical levels in the boiler water below normal control ranges. Additional chemicals should not be added as these residuals will increase through concentration mechanisms once the blowdown flow is stopped. Should boiler blowdown be necessary during the Test due to high conductivity or iron levels in the boiler water, the control operators should notify the Test Coordinator and the Test Manager who will then determine the most appropriate action based on the circumstances at the time.

9.3 Data Collection

An organized data collection effort will be required throughout the Test. The following items describe the tasks to be accomplished:

1. Log PI and CEMS Data. The PI system and CEMS test logs will be printed hourly. The logs will consist of sixty (60) one-minute averages plus the hourly average. The printed logs will be retained by the Test Manager, and copies provided to the Test Coordinator and to the Testing Contractor. The logs shall also be saved to a removable media on an hourly basis. The logs will be saved in a format which can be readily utilized using Microsoft® Excel.

2. Log manually collected data every 30 minutes.

3. Collect fuel samples per Attachment L.

4. Collect limestone samples per Attachment M.

5. Collect bed ash samples per Attachment N.

6. Collect fly ash samples per Attachment O.

7. Collect lime samples per Attachment P.

8. Measure fly ash flow rate based on isokinetic particulate test at SDA inlet and stoichiometric calculation of the flue gas flow rate.

9. Log CEMS data. See item 1 above.

9.4 Fuel Sampling

Fuel samples will be taken and analyzed according to the following schedule:

- 100% Load Test – at the start of the test and at the start of each hour of the test (applicable for both of the four-hour tests).

The fuel will not be sampled during the 40%, 60%, and 80% load tests.

Two (2) one-gallon samples will be taken from the sample port at the discharge end of each fuel feeder. The samples shall be collected using the coal scoop assembly provided with the feeders. One (1) of the one-gallon samples from each feeder will be sent to the test laboratory. The second fuel sample from each feeder will be retained in a mutually acceptable location until all parties have accepted the final test report. An independent laboratory approved by the Test Manager will be used for the analysis of the fuel samples.

All fuel samples will be stored in airtight containers to retain the moisture level in the fuel. Double bagging of the samples in plastic bags is recommended. Each of the bags shall be taped tightly shut. The samples shall be sealed immediately following collection.

The individual fuel samples will be identified using the label shown in Attachment G. Each fuel sample will have a sample number assigned using the methodology given on the bottom of the Fuel Sample Label sheet. The sample label shall be securely taped to the outside of the inner bag if the fuel samples are double bagged. The individual fuel samples will also be logged on the Incoming/Outgoing Sample Log Sheets shown in Attachment Q. The fuel samples will be sent to the laboratory as soon as possible following the completion of the load tests.

Each of the fuel samples taken for a given time period will be composited by the test laboratory into a single fuel sample for that time period.

9.4.1 Laboratory analyses to be performed

The laboratory shall prepare the following fuel analysis data for each composited sample:

1. Proximate Analysis – The as-received proximate analysis of each composite fuel sample shall be determined according to ASTM D3172. This shall determine the following:

    - Moisture (% wt)
    - Ash (% wt)
    - Volatile Matter (% wt)
    - Fixed Carbon (% wt)
    - Sulfur

2. Higher Heating Value – The dry basis Higher Heating Value (Btu/lb) of each composite fuel sample shall be determined according to ASTM D1989.

    Note: Fuels containing high ash or low volatile content do not completely burn in the bomb calorimeter, which affects the accuracy of the HHV result obtained. This poor combustion in the calorimeter does not affect normal monitoring of the plant performance, but boiler testing requires more accurate measurement. Therefore the ash/residue from the bomb calorimeter shall be analyzed for organic and inorganic carbon content, similar to the methods used for bed ash/fly ash. A correction shall be added to the calorimeter measured heating value based on a heating value of 14,500 Btu/lb of organic carbon in the residue.

3. Ultimate Analysis – The as-received ultimate analysis of each composite fuel sample shall be determined according to ASTM D3176. This shall determine the following:

    - Carbon
    - Hydrogen
    - Nitrogen
    - Oxygen
    - Ash
    - Moisture
    - Sulfur

Fuel shall also be analyzed for chlorine, fluorine, mercury, and lead. Testing for chlorine shall be according to ASTM D4208. Testing for fluorine shall be according to D3761. Testing for mercury shall be according to ASTM D3684. Testing for lead shall be according to ASTM D3683.

4. Fuel Ash Analysis – A fuel ash analysis of each composite fuel sample shall be completed according to ASTM D3682. This analysis shall determine the following ash constituents:

- V
- Ni
- Fe
- Na_2O
- SiO_2
- K_2O
- MgO
- SO_3
- P_2O_5
- Al_2O_3
- TiO_2
- CaO
- Fe_2O_3

5. Sieve Analysis – A complete dry sieve analysis shall be performed on the samples to determine size distribution. A sieve analysis on both a dry basis and a wet method basis shall be completed according to ASTM D4749. The analyses shall determine the percent passing through the mesh sizes shown in Attachment F, Table F-2.

9.4.2 Analysis Checklist

Attachment L provides a checklist that shall be used in requesting analysis of fuel samples by external labs.

9.5 Limestone Sampling

Limestone samples will be taken and analyzed according to the following schedule:

- 100% Load Test – at the start of the test and at the start of each hour of the test

The limestone will not be sampled during the 40%, 60%, and 80% load tests.

Two (2) one-gallon samples will be taken from the outlet of each operating limestone rotary feeders. The samples shall be collected using the scoop assembly provided with the feeders. One (1) of the one-gallon samples from each feeder will be sent to the test laboratory. The second limestone sample from each feeder will be retained in a mutually acceptable location until all parties have accepted the final test report. An independent laboratory approved by the Test Manager will be used for the analysis of the limestone samples.

All limestone samples will be stored in airtight containers. Double bagging of the samples in plastic bags is recommended. Each of the bags shall be taped tightly shut. The samples shall be sealed immediately following collection.

The individual limestone samples will be identified using the label shown in Attachment H. Each limestone sample will have a sample number assigned using the methodology given on the bottom of the Limestone Sample Label sheet. The sample label shall be securely taped to the outside of the inner bag if the limestone samples are double bagged. The individual limestone samples will also be logged on the Incoming/Outgoing Sample Log Sheets shown in Attachment Q. The limestone samples will be sent to the laboratory as soon as possible following the completion of the load tests.

Each set of limestone samples taken for a given time period will be composited by the test laboratory into a single limestone sample for that time period.

9.5.1 Laboratory analyses to be performed

The laboratory shall prepare the following limestone analysis data for each composited sample:

1. % by weight $CaCO_3$ – by x-ray fluorescence according to ASTM D4326-94, "Ash Chemical Analysis by X-Ray Fluorescence".

2. % by weight $MgCO_3$ – by x-ray fluorescence according to ASTM D4326-94, "Ash Chemical Analysis by X-Ray Fluorescence".

3. % by weight of Moisture – by oven drying to constant weight.

4. % by weight of Inerts – by difference.

5. Elemental analysis for lead, mercury, chlorine, fluorine, and alkali metals - Testing for chlorine shall be according to ASTM D4208. Testing for fluorine shall be according to D3761. Testing for mercury shall be according to ASTM D3684. Testing for lead shall be according to ASTM D3683. Testing for alkali metals shall be according to ASTM D2576.

6. TGA sorption test (Optional) – At JEA's discretion, samples shall be forwarded to an appropriate laboratory where a TGA Reactivity Index shall be determined using the laboratories recommended test methodology.

7. Sieve Analysis – A complete sieve analysis shall be performed on the composite limestone samples to determine size distribution. A sieve analysis on both a dry and wet method basis shall be completed according to ASTM D4749. The analyses shall determine the percent passing through the mesh sizes shown in Attachment F, Table F-2.

Attachment M provides a checklist which shall be used in requesting analysis of limestone samples by external labs.

9.6 Lime Slurry Sampling

Lime slurry samples will be taken and analyzed according to the following schedule:

- 100% Load Test – at the start of the test and at the start of each hour of the test

The lime slurry will not be sampled during the 40%, 60%, and 80% load tests.

The lime slurry feed rate to the atomizers will be measured concurrently with the lime slurry samples.

Lime slurry samples will be taken from the sample valve located on the discharge line from the slurry transfer pump (N01-RL-FV546). Two (2) samples of approximately 500 ml will be taken at each sampling event. Extreme care must be taken during sampling to protect skin and eyes from contact with the lime slurry.

One (1) set of lime slurry samples will be sent to the test laboratory. The second set of samples will be retained in a mutually acceptable location until all parties have accepted the final test report. An independent laboratory approved by the Test Manager will be used for the analysis of the limestone samples.

The individual lime samples will be stored in a glass sample container with a screw type top.

Each lime sample will have a sample number assigned using the methodology given on the bottom of the Lime Sample Label sheet. The sample label shall be securely taped to the outside of the sample bottle. The individual lime samples will also be logged on the Incoming/Outgoing Sample Log Sheets shown in Attachment Q. The lime slurry samples will be sent to the laboratory as soon as possible following the completion of the load tests.

The flow of lime into the SDA system as measured by the flow transmitter on the lime slurry line to the feed slurry transfer pumps (N01-RL34-FT535) will be recorded at the same time as the lime samples are taken.

9.6.1 Laboratory analyses to be performed:

The laboratory shall prepare the following lime analysis data for each composited sample:

1. % by weight CaO – ASTM C25-99
2. % by weight of solids – by oven drying to constant weight
3. % by weight inerts – by difference
4. Elemental analysis for lead, mercury, chlorine, fluorine, and alkali metals - Testing for chlorine shall be according to ASTM D4208. Testing for fluorine shall be according to D3761. Testing for mercury shall be according to ASTM D3684. Testing for lead shall be according to ASTM D3683. Testing for alkali metals shall be according to ASTM D2576.

9.6.2 Analysis Checklist

Attachment P provides a checklist which shall be used in requesting analysis of lime samples by external labs.

9.7 Fly Ash Sampling

During the 100% MCR Load Test, isokinetic sampling will be performed at the inlet to the SDA in order to determine ash loading rates and obtain samples for analysis. Also, ash will be sampled at the midpoint of the test at a single air heater and fabric filter hopper. Isokinetic sampling will not be performed during the 40%, 60%, and 80% Load Tests.

Fly ash sampling and flow rate will be determined by isokinetic sampling in accordance with EPA Method 17. Four one-hour traverses will be completed during each 100% MCR Load Test.

Samples for determination of the unburned carbon level in the fly ash will be taken using two Cegrit samplers located 180 degrees apart. Based on preliminary estimates of fly ash flow, Cegrit samples will be taken continuously throughout each one-hour Method 17 traverse.

The samples from the two opposing Cegrit analyzers will be combined to form a single composite sample for the sample period. One half of the composite sample will be sent to the test laboratory. The remaining half of the composite sample will be retained in a location acceptable to all parties of the test. An independent laboratory approved by the Test Manager will be used for the analysis of the fly ash samples.

All fly ash samples will be stored in airtight containers. Clean, unused, unpainted one-gallon paint cans are the recommended containers.

The individual fly ash samples will be identified using the label shown in Attachment J. Each fly ash sample will have a sample number assigned using the methodology given on the bottom of the Fly Ash Sample Label sheet. The sample label shall be securely taped to the outside of the ash sample containers. The individual fly ash samples will also be logged on the Incoming/Outgoing Sample Log Sheets shown in Attachment Q. The fly ash samples will be sent to the laboratory as soon as possible following the completion of the load tests.

Each set of fly ash samples taken for a given time period will be composited by the test laboratory into a single ash sample for that time period.

9.7.1 Laboratory analyses to be performed

The laboratory shall prepare the following fly ash analysis data for each composited sample:

1. Total Carbon in fly ash (% by weight) - Total carbon in the fly ash shall be determined using a LECO CHN 600 Analyzer (or equal) according to ASTM D3178. See Attachment R for a detailed description of the analytical method for determining organic and inorganic carbon.

2. Organic Carbon in fly ash (% by weight) – The organic carbon in the fly ash shall be determined using an HCl treated sample with a LECO CHN 600 Analyzer (or equal) according to ASTM D3178. See Attachment R for a detailed description of the analytical method for determining organic and inorganic carbon.

3. Calcium – The total calcium in the fly ash (% by weight) shall be determined according to ASTM D4326.

4. Sulfur – The total sulfur in the fly ash (% by weight) shall be determined according to ASTM D4239.

5. Ash Analysis – An ash analysis of each composite sample shall be completed according to ASTM D3682. This analysis shall determine the following ash constituents:

   - Vanadium
   - Nickel
   - Na_2O
   - Fe
   - SiO_2
   - K_2O
   - MgO
   - Fe_2O_2
   - SO_3

6. Sieve Analysis – A complete sieve analyses shall be performed on the composite fly ash samples to determine size distribution. A sieve analysis on both a dry and wet method basis shall be completed according to ASTM D4749. The analyses shall determine the percent passing through the mesh sizes shown in Attachment F, Table F-2.

9.7.2 Analysis Checklist

Attachment O provides a checklist that shall be used in requesting analysis of fly ash samples by external labs.

9.8 Bed Ash Sampling

Bed Ash samples will be taken and analyzed according to the following schedule:

- 100% Load Test – at the start of the test and at the start of each hour of the test

The bed ash will not be sampled during the 40%, 60%, and 80% load tests.

Two one-gallon samples will be taken from each of the operating stripper cooler rotary valves outlets through the 4 inch test port at each of these locations. One of the one-gallon samples from each stripper cooler will be sent to the test laboratory. The second sample from each stripper cooler will be retained in a mutually acceptable location until all parties have accepted the final test report. An independent laboratory approved by the Test Manager will be used for the analysis of the bed ash samples.

All bed ash samples will be stored in airtight containers. Clean, unused, unpainted one-gallon paint cans are the recommended containers

The individual bed ash samples will be identified using the label shown in Attachment I. Each bed ash sample will have a sample number assigned using the methodology given on the bottom of the Bed Ash Sample Label sheet. The sample label shall be securely taped to the outside of the ash sample containers. The individual bed ash samples will also be logged on the Incoming/Outgoing Sample Log Sheets shown in Attachment Q. The bed ash samples will be sent to the laboratory as soon as possible following the completion of the load tests.

Each set of bed ash samples taken for a given time period will be composited by the test laboratory into a single limestone sample for that time period.

9.8.1 Laboratory analyses to be performed

The laboratory shall prepare the following bed ash analysis data for each composited sample:

1. Total Carbon in bed ash (% by weight) - Total carbon in the bed ash shall be determined using a LECO CHN 600 Analyzer (or equal) according to ASTM D3178. See Attachment R for a detailed description of the analytical method for determining organic and inorganic carbon.

2. Organic Carbon in bed ash (% by weight) – The organic carbon in the bed ash shall be determined using an HCl treated sample with a LECO CHN 600 Analyzer (or equal) according to ASTM D3178. See Attachment R for a detailed description of the analytical method for determining organic and inorganic carbon.

3. Calcium – The total calcium in the bed ash (% by weight) shall be determined according to ASTM D3682.

4. Sulfur – The total sulfur in the bed ash (% by weight) shall be determined according to

ASTM D4239.

5. Ash Analysis – An ash analysis of each composite sample shall be completed according to ASTM D3682. This analysis shall determine the following ash constituents:

   - Vanadium
   - Nickel
   - Na_2O
   - Fe
   - SiO_2
   - K_2O
   - MgO
   - Fe_2O_2
   - SO_3

6. Sieve Analysis – A complete sieve analyses shall be performed on the composite bed ash samples to determine size distribution. A sieve analysis on both a dry and wet method basis shall be completed according to ASTM D4749. The analyses shall determine the percent passing through the mesh sizes shown in Attachment F, Table F-2.

9.8.2 Analysis Checklist

Attachment N provides a checklist which shall be used in requesting analysis of bed ash samples by external labs.

9.9 Bed Ash Flow Measurement

The Bed Ash flow rate is calculated as the difference between the total ash and fly ash. Fly ash will be collected during the Test by isokinetic sampling at the inlet to the SDA to determine the dust loading in the flue gas. The oxygen concentration at the SDA inlet will be simultaneously measured by multipoint traverse. The fuel flow is measured by gravimetric feeders. The flue gas flow rate will be identified from this information using stoichiometric calculations. The flue gas flow rate and the dust loading will provide the fly ash flow rate. The total ash flow rate is obtained from the heat and mass balance calculations associated with the boiler efficiency calculation.

9.10 Performance Test Log Sheets

Log sheets for test data collection shall be prepared onsite by the testing contractor and approved by the Test Coordinator based on the final DCS data acquisition format established for testing and also showing the designations applied for temporary Test instrumentation.

10.0 EMISSIONS TESTING

The following requirements shall apply for testing gaseous emissions.

10.1 Compliance Criteria

The compliance criteria will be based upon the design values set forth in Section 3.3 of this procedure.

10.2 Boiler Operation

Boiler operation and data collection requirements are the same as detailed in Section 9 above.

10.3 Gaseous Emissions

Gaseous emissions during the emissions test will be measured by certified calibrated continuous analyzers.

ATTACHMENTS

Attachment A

Fuel Fineness

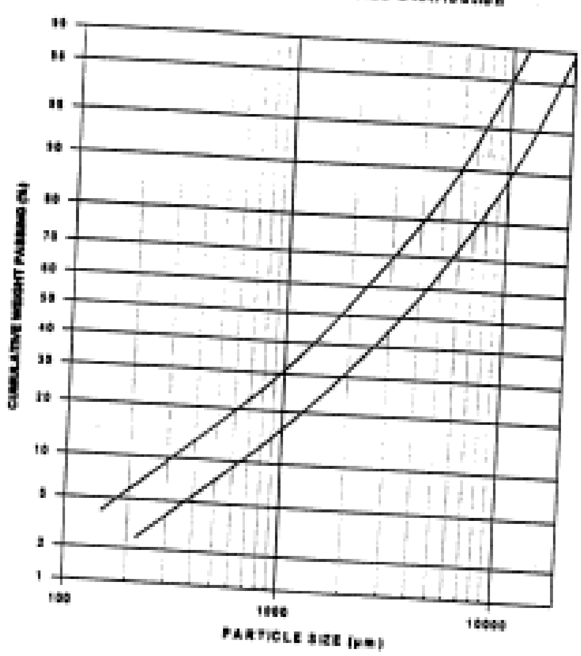
REQUISITION
FOSTER WHEELER USA CORPORATION

CHANGE NO. C1 DATE 6/12/99 PAGE 15 OF 17 REQUISITION NO. 4606-1351-A

Exhibit 3

PREFERRED COAL FEED SIZE DISTRIBUTION

Recommended Coal Size Distribution



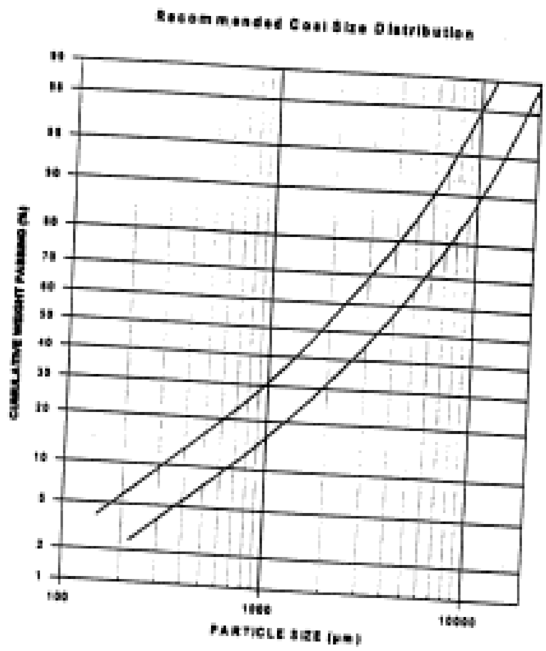
NOTE:
THE ABOVE COAL SIZE DISTRIBUTION RANGE IS FOR COAL PREPARATION SYSTEM DESIGN TO COVER THE RANGE OF COAL GIVEN IN SECTION 30 PAGE 1.2. FINAL SIZE DISTRIBUTION OF A GIVEN COAL WILL BE SELECTED BASED ON THE ACTUAL COAL AND WILL LIE WITHIN THE ABOVE RECOMMENDED RANGE.

REQUISITION
FOSTER WHEELER USA CORPORATION

CHANGE NO. C1	DATE 6/12/99		REQUISITION NO. 4605-1351-A	PAGE 15 OF 17

Exhibit 3

PREFERRED COAL FEED SIZE DISTRIBUTION



NOTE:
THE ABOVE COAL SIZE DISTRIBUTION RANGE IS FOR COAL PREPARATION SYSTEM DESIGN TO COVER
THE RANGE OF COAL GIVEN IN SECTION 30 PAGE 1.2. FINAL SIZE DISTRIBUTION OF A GIVEN
COAL WILL BE SELECTED BASED ON THE ACTUAL COAL AND WILL LIE WITHIN THE ABOVE RECOMMENDED
RANGE.

Attachment B

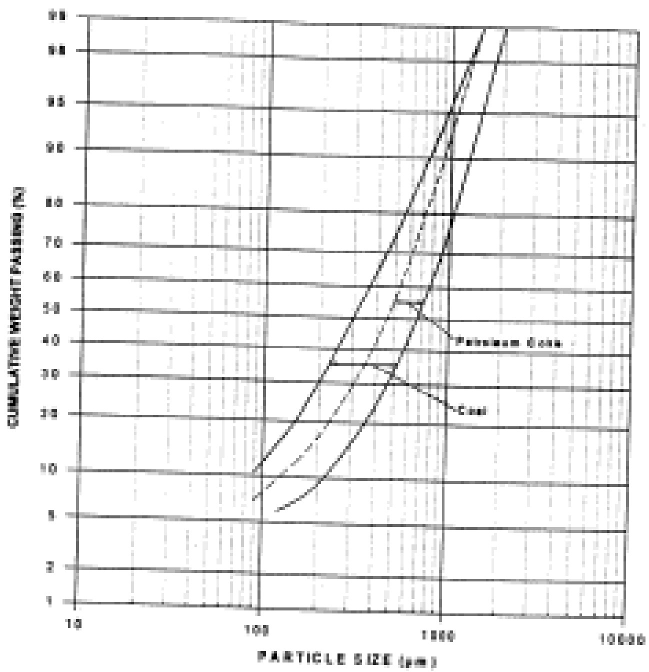
Limestone Fineness

REQUISITION
FOSTER WHEELER USA CORPORATION

PAGE 45 OF 45

CHANGE NO. CO DATE 6/13/99 REQUISITION NO. 4605-2351-A

Exhibit 1
Recommended Range of Limestone Size Distribution



Attachment C

Fuel and Limestone Specification

Building Community

FUEL SPECIFICATIONS

Coal (Pittsburgh 8)		**Range**	
	Performance (Note 12)	**Minimum**	**Maximum**
Heat Content, Btu/lb (HHV)	12,690	11,600	13,959
Hardgrove Grindability	NA	NA	NA
As Received Particle Size (Inches)	NA	NA	NA
Ash Fusion (reducing, soft, ºF)	NA	NA	NA
Volatile Matter (% DAF)	43.41	39.1	47.0
Proximate Analysis			
Volatile Matter	35.6	NA	(Note 4)
Fixed Carbon	46.4	NA	NA
Moisture	5.2 (Note 8)	NA	12.0
Ash (Note 3)	12.8	7.0	15.0
Ultimate Analysis			
Carbon	68.6	66.6	70.6
Hydrogen	4.6	4	5.2
Nitrogen	1.3	0.8	1.6
Oxygen	4.11	3.98	4.2
Chlorine	0.09	NA	0.1
Sulfur (Note 3)	3.3	2.97	3.6
Moisture	5.2 (Note 8)	NA	12.0
Ash (Note 3)	12.8	7.0	15.0
Fluoride	NA	NA	NA
Lead	NA	NA	NA
Mercury	NA	NA	NA
Mineral Analysis of Coal Ash			
Phosphorous Pentoxide	WR	WR	WR
Silicon Oxide	WR	WR	WR
Ferric Oxide	WR	WR	WR
Aluminum Oxide	WR	WR	WR
Titanium Oxide	WR	WR	WR
Calcium Oxide	WR	WR	WR
Magnesium Oxide	WR	WR	WR
Sulfur Trioxide	WR	WR	WR
Potassium Oxide	WR	WR	WR
Sodium Oxide	WR	WR	WR

FUEL SPECIFICATIONS (cont'd)

Coal (Illinois 6)

	Performance	Range Minimum	Range Maximum
Heat Content, Btu/lb (HHV)	11,603	11,499	11,738
Hardgrove Grindability	53.13	50	57
Ash Fusion (reducing, soft, ºF)	2051	2020	2130
Proximate Analysis			
Volatile Matter	36.33	35.55	36.88
Fixed Carbon	43.99	43.35	44.50
Moisture	11.11	10.64	11.96
Ash	8.57	7.79	8.85
Ultimate Analysis, Dry			
Carbon	72.54	71.44	73.20
Hydrogen	4.55	4.70	5.22
Nitrogen	1.39	1.25	1.48
Oxygen	8.42	7.73	9.29
Chlorine	0.17	0.13	0.18
Sulfur	3.05	2.89	3.19
Ash	9.64	8.77	9.96
Mineral Analysis of Coal Ash			
Phosphorous Pentoxide	0.39	0.26	0.48
Silicon Oxide	49.26	48.36	50.82
Ferric Oxide	20.09	18.32	21.98
Aluminum Oxide	19.92	18.59	21.20
Titanium Oxide	1.01	0.94	1.10
Calcium Oxide	3.05	2.77	3.53
Magnesium Oxide	0.91	0.73	1.06
Sulfur Trioxide	1.93	1.59	2.25
Potassium Oxide	2.46	2.23	2.65
Sodium Oxide	0.80	0.70	0.90

FUEL SPECIFICATIONS (cont'd)

Delayed Petroleum Coke

	Minimum	Maximum	Performance	Performance Range Minimum	Performance Range Maximum
Heat Content, Btu/lb (HHV)	13,000	NA	14,000	13900	NA
Hardgrove Grindability	25.0	80.0	WR	WR	WR
As Received Particle Size (Inches)	0.0	4.0	NA	NA	NA
Proximate Analysis					
Volatile Matter	7.0	14.0	9.0	7.0	11.0
Fixed Carbon	71.0	88.0	81.6	NA	NA
Moisture	NA	15.0 (Note 8)	9.0	NA	15.0
Ash	NA	3.0	0.4	NA	3.0
Ultimate Analysis					
Carbon	78.0	89.0	79.0	79.0	85.0
Hydrogen	3.2	5.8	3.6	3.25	4.17
Nitrogen	0.4	2.0	1.0	0.73	1.6
Oxygen	0.1	1.8	0.3	0.3	1.65
Sulfur	3.0	8.0	6.7	4.0	8.0
Moisture	NA	15.0 (Note 8)	9.0	NA	15.0
Ash	NA	3.0	0.4	NA	3.0
Vanadium, ppm	NA	3500 (Note 9)	NA	NA	NA
Nickel, ppm	NA	600 (Note 9)	NA	NA	NA
Fluoride	NA	Note 5	NA	NA	NA
Lead	NA	Note 5	NA	NA	NA
Mercury	NA	Note 5	NA	NA	NA
Chlorine	NA	Note 11	NA	NA	NA
Alkalis	NA	Note 10	NA	NA	NA

Note:

1. NA = no limit available
2. All data is for fuel "as received" on a percent mass basis unless noted.
3. Coal minimum sulfur content is 0.5% given at least 12.0% ash. Coal minimum ash content is 7.0% given at least 1.0% sulfur. For coals with sulfur content between 0.5% and 1.0% and ash content between 7% and 12%, the minimum coal ash content as a function of sulfur content shall be as shown in Figure 2.5.
4. The maximum coal volatile matter is 47% on a dry-ash free basis.
5. The emissions guarantee shall be based upon uncontrolled emissions as resulting from the combined inputs from fuel and limestone that do not exceed the following values:

   Lead - 0.00278 lb/Mbtu (HHV)
   Mercury - 0.0000174 lb/Mbtu (HHV)
   Fluorine (as HF) - 0.0106 lb/Mbtu (HHV)
6. WR = within range
7. Not Used.
8. Surface moisture of the crushed fuel should be below 10% to avoid conveying and feeding hang-ups.
9. The total vanadium and nickel content in the fuel should not exceed 2,000 ppm. Operation at higher levels than 2,000 ppm will result in increased outages for unit cleaning and repairs.
10. The fuels fired in the boiler should have a combined acetic acid soluble sodium (Na) and potassium (K) content less than 0.05% (500 ppm) on a dry fuel basis to prevent bed sintering and agglomeration.
11. The chlorine levels in the fuel should be less than 0.1% on a dry fuel basis to avoid corrosion and agglomeration problems.
12. Performance coal will be Eastern US coal.
13. Not Used.

Performance Limestone Properties

The limestone sizing as delivered at the limestone preparation building will be as per ASTM-33-93 for sizes 57, 67, 7, or 8, and a Bond Work Index of 12.

	Performance (Note 1)	Minimum	Maximum
$CaCO_3$, % by weight	92.0	85.0	99.0
$MgCO_3$, % by weight	3.0	0.2	5.0
Inerts, % by weight	4.0	NA	15.0
Moisture, % by weight	1.0	NA	10.0
Trace Elements, Max Content			
Fluorine, mg/kg	NA	NA	Note 2
Lead, mg/kg	NA	NA	Note 2
Mercury, mg/kg	NA	NA	Note 2
Chlorine, ppm	NA	NA	1,200

Note 1: When firing petroleum coke, the limestone must be "land" based type.

Note 2: The above indicated lead, mercury, and fluorine contents are provided as the expected concentrations. The emissions guarantee shall be based upon uncontrolled emissions as resulting from the combined inputs from fuel and limestone that do not exceed the following values:

Lead - 0.00278 lb/Mbtu (HHV)
Mercury - 0.0000174 lb/Mbtu (HHV)
Fluorine (as HF) - 0.0106 lb/Mbtu (HHV)

Note 3: Performance moisture listed in this table is the moisture level measured at the boiler

Note 4: The 10% maximum moisture content listed in the Table is the maximum as received moisture content in the limestone – it is dried to a design value of 1% moisture in the limestone preparation system, prior to injection into the boiler.

Attachment D

Example Calculations for Deviations from Operating Conditions

Boiler Efficiency

Spreadsheets detailing the method used to compute boiler efficiency are included in Attachment S. The comments column of the spreadsheet describes the calculation methods used in detail. The spreadsheet uses the heat loss method to compute boiler efficiency. The boiler losses evaluated by the spreadsheet are as follows:

a. Dry Flue Gas Loss – This loss is evaluated using the gas temperature leaving the airheater and the reference air temperature based on the actual test conditions. The loss is corrected to design point conditions by using the Performance Fuel properties for HHV and for the pounds of dry flue gas per pound of fuel.

b. Loss Due to Moisture in Fuel – This loss is evaluated using the gas temperature leaving the airheater and the reference air temperature based on the actual test conditions. The loss is corrected to design point conditions by using the Performance Fuel properties for HHV and for the fuel moisture content.

c. Loss Due to Moisture from Combustion of Hydrogen – This loss is evaluated using the gas temperature leaving the airheater and the reference air temperature based on the actual test conditions. The loss is corrected to design point conditions by using the Performance Fuel properties for HHV and the fuel hydrogen content.

d. Combustible Loss – This loss is evaluated using the unburned carbon content of the bed ash and the fly ash measured during the test.

e. Carbon Monoxide Loss – This is assumed to be zero.

f. Sensible Heat in Ash – The measured value from the 100% load test is to be used and will also be used as the basis for estimating the sensible heat in ash at the other loads.

g. Calcination/Sulfation – The methodology in 4.2.4 for the 100% load test will be used. This value will also be the basis for estimating the calcination/sulfation at the other loads.

h. Moisture in Air Loss – This loss is evaluated using the gas temperature leaving the airheater and the reference air temperature based on the actual test conditions. The design value for pounds of moisture per pound of dry air is utilized.

The design boiler efficiency will also be corrected for deviation from design boiler feedwater temperature using Figure 3.5.1 which is included in Attachment T.

Corrected Efficiency = Test Efficiency Corrected to Guarantee Conditions + Correction from Figure 3.5.1

Correction to Main Steam Flow for Deviation in Feedwater Temperature

Main steam flow will be corrected for deviation from the design feedwater temperature using Figure 3.5.2 which is included in Attachment T.

Corrected Steam Flow = Test Steam Flow x Capacity Factor from Figure 3.5.2

Correction to Hot Reheat Steam Temperature for Deviation in Cold Reheat Temperature

Hot reheat steam temperature will be corrected for deviation from the design cold reheat steam temperature using Figure 3.5.3 which is included in Attachment T.

Corrected HRH Steam Temperature = Test HRH Steam Temperature + Correction from Figure 3.5.3.

Correction to Main Steam Temperature for Deviation in Feedwater Temperature

Main steam temperature will be corrected for deviation from the design feedwater temperature using Figure 3.5.4 which is included in Attachment T.

Corrected Main Steam Temperature = Test Main Steam Temperature + Correction from Figure 3.5.4

Correction to Mercury, Lead, and HF Emissions for Excess Uncontrolled Emissions

If the uncontrolled emissions of any of these constituents exceed the limits detailed in section 3.3, the test emissions values shall be corrected for variation from the Reference Condition as follows:

Corrected Emissions = Test Emissions x (Reference Uncontrolled Emissions/Test Uncontrolled Emissions)

Attachment E

Measurement Uncertainty Calculations

PERFORMANCE TEST

The mutually agreed measurement uncertainty values for all the performance guarantees related to the Performance Test are specified in Section 6.2.4 of this Test Procedure. Based on these MU values, the following three tables (1, 2, & 3) have been developed. A copy of these tables is included in this Attachment.

TABLE 1 **WORK SHEET FOR CALCULATION**

Table 1 is an "Excel" work sheet file for the Fuel Capability Demonstration Test measurement uncertainty calculations. This table shows the following parameters starting with the column on the left:

Column #	Description
1	Design Point description
2	"Design Point Value" for each parameter
3	"Units" on which the design values are specified
4	"MU Adjusted Acceptable Measured Low Value" of the design value
5	"MU Adjusted Acceptable Measured High Value" of the design value
6	"MU Value" mutually agreed for each design value
7	"Test Results Average Value" input
8	"Test Results" rounded off to the same decimal place as for each design value
9	"MET" or "NOT MET" evaluation of the Test results

The logic used in the MET/NOT MET evaluation is:

For the Capacity and efficiency

If the Test result average value is equal to or higher than the minimum acceptable MU adjusted low value, then the Test "MET" that particular design point.

For the Emissions

It is not appropriate to use the MU adjusted low value in all cases since MU is not applied to emissions test results. Therefore, in these cases the low and high values are identical.

For the Steam Temperatures

If the Test result average value is lower than the minimum acceptable MU adjusted low value, then the Test "NOT MET" that particular design value.

In all the cases, Test results (average values) will be rounded off to the same decimal place as shown in the Contract for each corresponding design point.

TABLE 2 **EXAMPLE WORK SHEET SHOWING ALL "MET"**

Table 2 gives example calculations to demonstrate the use of Table 1. This table shows the worst Test values that demonstrate successfully meeting each performance design value.

TABLE 3 **EXAMPLE WORK SHEET SHOWING ALL "NOT MET"**

Table 3 also gives example calculations to demonstrate the use of Table 1. This table shows the best Test values that demonstrate failure meeting each performance design value.

TABLE 1

JEA NORTHSIDE UNIT 2 FUEL CAPABILITY DEMONSTRATION TEST

WORK SHEET FOR DESIGN POINT 'MET" OR "NOT MET" EVALUATION DURING PERFORMANCE TEST
IN CONSIDERATION OF MEASUREMENT UNCERTAINTY AND ROUNDING OFF OF TEST RESULTS

ENTER TEST DATA WITH ONE MORE DECIMAL PLACE THAN THE CORRESPONDING GUARANTEE

Performance	Design Point Value	Units	MU Adjusted Acceptable Measured Low Value	MU Adjusted Acceptable Measured High Value	MU Value (relative)	Test Results Average Value	Test Results Average Value Rounded	Perf Test Guarantee "MET" or "NOT MET"
Efficiency Design Point	90.07	%	89.27	90.89	0.0090			
Test result							0.00	**NOT MET**
Capacity Guarantee								
Maximum (100% MCR)	1,993,591	lb/hr	1,956,419	2,032,203	0.0190			**NOT MET**
Test result		lb/hr					0	
Emissions								
NOx Value	0.09	lb/MMbtu	0.09	0.09	0.0000			**MET**
Test result							-	
SO2 in flue gas	0.015	lb/MMbtu	0.015	0.015	0.0000			**MET**
Test result							-	
Particulate	0.011	lb/MMbtu	0.011	0.011	0.0000			**MET**
Test result							-	
Main Steam Temperature								
Load > 75% MCR								
Target Temp	1,000	F	995	1,015	0.0050			
High Range (+10F)	1,010	F						**NOT MET**
Low Range (-0F)	1,000	F						
Test result							0	
Load < 75% MCR								
Target Temp	1,000	F	985	1,015	0.0050			
High Range (+10F)	1,010	F						**NOT MET**
Low Range (-10F)	990	F						
Test result							0	
Reheat Steam Temperature								
Load > 75% MCR								
Target Temp:	1,000	F	995	1,015	0.0050			
High Range (+10F):	1,010	F						**NOT MET**
Low Range (-0F):	1,000	F						
Test result							0	
Load < 75% MCR								
Target Temp	1,000	F	985	1,015	0.0050			
High Range (+10F)	1,010	F						**NOT MET**
Low Range (-10F)	990	F						
Test result							0	

TABLE 2

JEA NORTHSIDE UNIT 2 FUEL CAPABILITY DEMONSTRATION TEST

EXAMPLE CALCULATION SHOWING ALL DESIGN POINTS "MET"

Performance	Design Point Value	Units	MU Adjusted Acceptable Measured Low Value	MU Adjusted Acceptable Measured High Value	MU Value (relative)	Test Results Average Value	Test Results Average Value Rounded	Perf Test Guarantee "MET" or "NOT MET"
Efficiency Design Point	90.07	%	89.27	90.89	0.0090			
Test result						89.265	89.27	**MET**
Capacity Guarantee								
Maximum (100% MCR)	1,993,591	lb/hr	1,956,419	2,032,203	0.0190			**MET**
Test result		lb/hr				1,956,418.5	1,956,419	
Emissions								
NOx Value	0.09	lb/MMbtu	0.09	0.09	0.0000			**MET**
Test result						0.094	0.09	
SO2 in flue gas	0.015	lb/MMbtu	0.015	0.015	0.0000			**MET**
Test result						0.0154	0.0150	
Particulate	0.011	lb/MMbtu	0.011	0.011	0.0000			**MET**
Test result						0.0114	0.011	
Main Steam Temperature								
Load > 75% MCR								
Target Temp	1,000	F	995	1,015	0.0050			
High Range (+10F)	1,010	F						**MET**
Low Range (-0F)	1,000	F						
Test result						994.5	995	
Load < 75% MCR								
Target Temp	1,000	F	985	1,015	0.0050			
High Range (+10F)	1,010	F						**MET**
Low Range (-10F)	990	F						
Test result						984.5	985	
Reheat Steam Temperature								
Load > 75% MCR								
Target Temp:	1,000	F	995	1,015	0.0050			
High Range (+10F):	1,010	F						**MET**
Low Range (-0F):	1,000	F						
Test result						994.5	995	
Load < 75% MCR								
Target Temp	1,000	F	985	1,015	0.0050			
High Range (+10F)	1,010	F						**MET**
Low Range (-10F)	990	F						
Test result						984.5	985	

TABLE 3

JEA NORTHSIDE UNIT 2 FUEL CAPABILITY DEMONSTRATION TEST

EXAMPLE CALCULATION SHOWING ALL DESIGN POINTS "NOT MET"

Performance	Design Point Value	Units	MU Adjusted Acceptable Measured Low Value	MU Adjusted Acceptable Measured High Value	MU Value (relative)	Test Results Average Value	Test Results Average Value Rounded	Perf Test Guarantee "MET" or "NOT MET"
Efficiency Design Point	90.07	%	89.27	90.89	0.0090			
Test result						89.264	89.26	**NOT MET**
Capacity Guarantee								
Maximum (100% MCR)	1,993,591	lb/hr	1,956,419	2,032,203	0.0190			**NOT MET**
Test result		lb/hr				1,956,418.4	1,956,418	
Emissions								
NOx Value	0.09	lb/MMbtu	0.09	0.09	0.00			**NOT MET**
Test result						0.095	0.10	
SO2 in flue gas	0.015	lb/MMbtu	0.015	0.015	0.0000			**NOT MET**
Test result						0.0155	0.016	
Particulate	0.011	lb/MMbtu	0.011	0.011	0.0000			**NOT MET**
Test result						0.0115	0.012	
Main Steam Temperature								
Load > 75% MCR								
Target Temp	1,000	F	995	1,015	0.0050			
High Range (+10F)	1,010	F						**NOT MET**
Low Range (-0F)	1,000	F						
Test result						994.4	994	
Load < 75% MCR								
Target Temp	1,000	F	985	1,015	0.0050			
High Range (+10F)	1,010	F						**NOT MET**
Low Range (-10F)	990	F						
Test result						984.4	984	
Reheat Steam Temperature								
Load > 75% MCR								
Target Temp:	1,000	F	995	1,015	0.0050			
High Range (+10F):	1,010	F						**NOT MET**
Low Range (-0F):	1,000	F						
Test result						994.4	994	
Load < 75% MCR								
Target Temp	1,000	F	985	1,015	0.0050			
High Range (+10F)	1,010	F						**NOT MET**
Low Range (-10F)	990	F						
Test result						984.4	984	

Attachment F

List of Parameters and Data Collection Methods for Capacity, Efficiency, and Emissions Calculations

Table F-1

Laboratory and Manual Test Sampling Procedures

Sample	**Sampling Location**	**Sample Type**[1]	**Sample Size**	**Frequency / Duration**	**Sampling Procedures**
Fuel	Fuel feeder outlets	grab	2 – 1 gallon samples	1/hr during 100% MCR test, 2 total for each reduced load test	Manually composite grab samples
Limestone	Limestone rotary feeder outlets	grab	2 -1 gallon samples	1/hr during 100% MCR test, no samples during reduced load test	Manually composite grab samples
Bed Ash	Stripper cooler rotary valve outlets	grab	2 - 1 gallon samples	1/hr 100% MCR test, 1 at midpoint each reduced load test	Manually composite grab samples
Fly Ash	AH outlet duct Cegrit sampling and air heater economizer, economizer, and fabric filter hopper samples	Cegrit and hopper grabs	2 - 1 gallon samples	1 Cegrit sample /hr during 100% MCR test, & 1 hopper sample at midpoint test	Manually composite grab samples
Lime	Lime feeder A or B	grab	1 lb	1/hr when slaking	Manually composite grab samples
Flue Gas	SDA inlet ductwork test ports SDA inlet ductwork Stack Stack Stack sampling ports	composite CEM CEM OM composite	NA NA NA NA NA	3 tests per run Continuous Continuous Continuous 3 tests per run	Temporary duct test probes. 6-min average Temporary stack test probes

[1] CEM – continuous emissions monitor, OM – opacity monitor

Table F-2

Laboratory Test Procedures

Sample	Parameter	Test Procedure	Testing Organization
Fuel	Proximate analysis – moisture, ash, volatiles, fixed carbon, sulfur	ASTM D3172	
	Higher heating value	ASTM D1989 (ASTM D3286 if HHV < 10,000 Btu/lb)	
	Ultimate analysis – carbon, hydrogen, sulfur, nitrogen, oxygen	ASTM D3176	
	Chlorine	ASTM D4208	
	Fluorine	ASTM D3761	
	Mercury	ASTM D3684	
	Lead	ASTM D3683	
	Moisture	By oven drying to constant weight	
	Ash elemental analysis – V, Ni, Fe, Na_2O, SiO_2, K_2O, MgO, SO_3, P_2O_5, Al_2O_3, TiO_2, CaO, Fe_2O_3	ASTM D3682	
	Particulate size distribution - ½", ¼", #4, #8, #14, #28, #48, #100 Tyler mesh	ASTM D4749 Dry Sieve above #100 mesh (note: particle size distribution testing for particles #100 mesh and smaller shall be done by laser particle size testing.)	
Limestone	$CaCO_3$, $MgCO_3$	ASTM D4326	
	Moisture	Oven drying to constant weight	
	Inerts	By difference	
	Chlorine	ASTM D4208	
	Fluorine	ASTM D3761	
	Mercury	ASTM D3684	
	Lead	ASTM D3683	
	Na		
	K		

Table F-2

Laboratory Test Procedures

Sample	Parameter	Test Procedure	Testing Organization
Limestone (cont'd)	Particle size distribution (as fed to boiler) - #8, #14, #28, #48, #100, #200, #270 Tyler mesh	ASTM D4749 Dry Sieve above #100 mesh (note: particle size distribution testing for particles #100 mesh and smaller shall be done by laser particle size testing.)	
Lime	CaO Solids Inerts Chlorine Fluorine Mercury Lead Na K	ASTM C25-99 Oven drying to constant weight By difference ASTM D4208 ASTM D3761 ASTM D3684 ASTM D3683	
Fly Ash (leaving air heater)	Unburned carbon (LOI) CaO $CaSO_4$ Sulfur V, Ni, Na_2O, Fe, SiO_2, K_2O, MgO, Fe_2O_3, SO_3 Na K Particulate size distribution - #4, #14, #28, #48, #100, #270, #325 Tyler mesh	 ASTM D4326 ASTM D4239 ASTM D3682 ASTM D4749 Dry Sieve above #100 mesh (note: particle size distribution testing for particles #100 mesh and smaller shall be done by laser particle size testing.)	

Table F-2

Laboratory Test Procedures

Sample	Parameter	Test Procedure	Testing Organization
Bed Ash	Unburned carbon (LOI)		
	CaO		
	$CaSO_4$		
	Sulfur	ASTM D4239	
	V, Ni, Na_2O, Fe, SiO_2, K_2O, MgO, Fe_2O_3, SO_3	ASTM D3682	
	Na		
	K		
	Particulate size distribution - ½", ¼", #4, #8, #14, #28, #48, #100, #200 Tyler mesh	ASTM D4749 Dry Sieve above #100 mesh (note: particle size distribution testing for particles #100 mesh and smaller shall be done by laser particle size testing.)	
Flue Gas	PM, PM_{10}	Method 5 and 202	
	NO_x	CEM	JEA
	SO_2	CEM (outlet) DCS (inlet)	JEA
	CO	CEM	JEA
	CO_2	CEM	JEA
	NH_3	Method CTM-027	
	Pb (once only at MCR)	Method 0012	
	Hg (once only at MCR)	Method 29 & Ontario Hydro Method	
	F (once only at MCR)	Method 0300.0	
	Dioxin (Pittsburgh 8 only) (once only at MCR)	Method 1613A	
	Furan (Pittsburgh 8 only) (once only at MCR)	Method 1613A	
	Opacity	Opacity monitor	JEA

Table F-3

DCS Information

Substance	**Characteristic being Measured**	**Instrument Tag #, Remark**
Ambient Air	Dry Bulb Temperature, °F	BY JEA - NEED TAG NUMBER
	Wet Bulb Temperature, °F	
	Barometric Pressure, in Hg	
Primary Air	Fan Inlet Temperature, °F	Outdoor Unit - Use Ambient Dry Bulb
	Fan Outlet Temperature, °F	BN-34-TE-719/619 (A/B)
Secondary Air	Fan Inlet Temperature, °F	Outdoor Unit - Use Ambient Dry Bulb
	Fan Outlet Temperature, °F	BN-34-TE-569/519 (A/B)
	Total SA Flow, klb/hr	BN-34-FI-571/521 (A/B)
Total Air	Flow, kbl/hr	2TOTAIRFLOW
Fuel	Fuel Feeder Flow, klb/hr	FN-34-FT-508/528/548/568/588/608/628/668 (Feeders B1/B2/C1/C2/D1/D2/A/E)
	Fuel Composition, As Fired % Mass	Laboratory Analysis of Coal Samples Obtained by Grab Sampling
	HHV, Btu/lb	Laboratory Analysis of Coal Samples Obtained by Grab Sampling
	Total Fuel Flow, klb/hr	2SOLIDFUELFLW

Table F-3

DCS Information

Substance	**Characteristic being Measured**	**Instrument Tag #, Remark**
Flue Gas	SAH Gas In Temperature, °F	BO-34-TE-516/517 (A/B)
	PAH Gas In Temperature, °F	BO-34-TE-518/519 (A/B)
	SAHTR Gas Out, °F	BO-34-TE-527/528/529 (A SIDE) BO-34-TE-530/531/532 (B SIDE)
	PAHTR Gas Out, °F	BO-34-TE-537/538/539 (A SIDE) BO-34-TE-540/541/542 (B SIDE)
	Bed Pressure, in wg	BB-34-PT-423/473/483
	Bed Temperature, °F	BB-34-TE-412-417/406-411 (LEFT) BB-34-TE-400-405/462-467 (CENTER) BB-34-TE-456-461/450-455 (RIGHT)
	Furnace Bed Average Temperature, °F	2AVGFBTMP
	Boiler Exit O_2, % Wet	BO-34-AT-510/511
	SAHTR Exit O_2, % Wet	Plant Instrument AIT0800D
Stripper/ Cooler A	Rotary Valve Speed, %	NB-34-ST-552
	SC-A Bed 3 Temperature Leaving SC, °F	NB-34-TE-553/554
	SC-A Bed 3 Temperature Entering SC, °F	NB-34-TE-550
Stripper/ Cooler B	Rotary Valve Speed, %	NB-34-ST-662
	SC-B Bed 3 Temperature Leaving SC, °F	NB-34-TE-653/654
	SC-B Bed 3 Temperature Entering SC, °F	NB-34-TE-650

Table F-3
DCS Information

Substance	Characteristic being Measured	Instrument Tag #, Remark
Stripper/ Cooler C	Rotary Valve Speed, %	NB-34-ST-612
	SC-C Bed 3 Temperature Leaving SC, °F	NB-34-TE-603/604
	SC-C Bed 3 Temperature Entering SC, °F	NB-34-TE-600
Stripper/ Cooler D	Rotary Valve Speed, %	NB-34-ST-512
	SC-D Bed 3 Temperature Leaving SC, °F	NB-34-TE-503/504
	SC-D Bed 3 Temperature Entering SC, °F	NB-34-TE-500
Main Steam at Boiler	Flow, kbl/hr	Calculated = Feedwater + Spray
	Pressure, psig	SJ-34-PT-549
	Temperature, °F	SI-34-TE-556/557 (FSH OUTLET)
Reheat Steam Inlet at Boiler	Flow, kbl/hr	Calculated = TG throttle flow less extraction to #1 heater (based on heat balance vs. feedwater) and less TG seal leakages. Add RH spray for HRH flow.
	CRH Pressure, psig	SE-34-PT-531
	CRH Temperature, °F	SE-34-TE-531
Reheat Steam Outlet at Boiler	Hot Reheat Pressure, psig	SH-34-PT-510
	HRH Outlet Temperature, °F	SH-34-TE-510/511

Table F-3

DCS Information

Substance	**Characteristic being Measured**	**Instrument Tag #, Remark**
Feedwater at Boiler	Flow Economizer Inlet, klb/hr	QF-34-FT-501
	Pressure at Economizer Inlet, psig	QF-34-PT-510
	Temperature at Economizer Inlet, °F	QF-34-TE-510
Continuous Blowdown	Pressure, psig (Drum Pressure)	BB-34-PT-500/501/502
	Temperature, °F (At Drum Pressure)	Calculated
	Flow Rate, lb/hr	Calculated based on Valve Position
DSH Spray Water	Flow, klb/hr	QF-34-FT-500
	Pressure, psig	QF-34-PT-500
	Temperature, °F	QF-34-TE-500
RH Spray Water	Flow, klb/hr	SE-34-FT-582
	Pressure, psig	SE-34-PT-542
	Temperature, °F	SE-34-TE-542
Bottom Ash	Envelope Boundary Temperature, °F	
	Composition, %Mass	Laboratory Analysis of Bottom Ash Samples Obtained by Grab Sampling
Fly Ash	Composition, %Mass	Laboratory Analysis of Fly Ash Samples Obtained by Grab Sampling
	Flow, lb/hr	Isokinetic Sample Collection

Table F-3
DCS Information

Substance	Characteristic being Measured	Instrument Tag #, Remark
Main Steam at Turbine	Flow, klb/hr	2SF_KLB_H
	Pressure, psig	2IP-PSJ-34-PT-509/599 (BYPASS)
	Temperature, °F	SJ-34-TE-066/067 (GE) SJ-34-TE-509 (BYPASS)
Hot Reheat Steam at Turbine	Pressure, psig	2HRHP-PSJ-34-PT-507 (BYPASS)
	Temperature, °F	2TT-RHS-1/2 SJ-34-TE-507 (BYPASS)
Feedwater Heater #1 Extraction	Pressure, psig	SD-34-PT-001
	Temperature, °F	SD-34-TE-001
Feedwater Heater #1 Drain	Pressure, psig	Use Extraction Pressure
	Temperature, °F	HK-34-TE-001
Feedwater Heater #1 Feedwater Entering	Pressure, psig	QF-34-PT-510 (FEEDWATER)
	Temperature, °F	QF-34-TE-001
Feedwater Heater #1 Feedwater Leaving	Pressure, psig	QF-34-PT-510 (FEEDWATER)
	Temperature, °F	QF-34-TE-510
AQC Inlet	SO_2 Concentration, lb/Mbtu	BO-34-AT-512/513
	Pressure, psig	RA-34-PT-502
	Temperature, °F	RA-34-TE-501

Table F-3
DCS Information

Substance	Characteristic being Measured	Instrument Tag #, Remark
Scrubber Outlet	Pressure, psig	RA-34-PT-503
	Temperature, °F	RA-34-TE-505/506/507/508
Baghouse Outlet	Pressure, psig	RB-34-PT-900
	Temperature, °F	RB-34-TE-901
Economizer Outlet - Sample Extraction	O_2, % wv	Temporary Test Instrument
	SO_2 Concentration, ppm dv	Temporary Test Instrument
	NO_x, ppm dv	Temporary Test Instrument
	CO, ppm dv	Temporary Test Instrument
	Particulate, mg/Nm^3	Temporary Test Instrument
Stack Emission - CEMS	SO_2 Concentration, ppm wv	LB-34-AY-534
	SO_2 Emission, lb/Mbtu	LB-34-AY-535
	NO_x Concentration, ppm wv	LB-34-AY-532
	NO_x Emission, lb/Mbtu	LB-34-AY-533
	Opacity, %	LB-34-AT-540
	CO_2, % wv	LB-34-AT-538
	CO, ppm wv	LB-34-AT-536
	Flue Gas Flow, kscfm	LB-34-FT-550
DeNOx Ammonia	Flow, GPH	UR-34-FT-522

Table F-3
DCS Information

Substance	Characteristic being Measured	Instrument Tag #, Remark
Boiler Drum	Pressure, psig	BB-34-PT-500/501/502
	Level, in	BB-34-LT-500/501/502
Boiler Economizer Outlet	Temperature, °F	QF-34-TE-512/514
PA Booster Fan	Flow, klb/hr	BN-34-FI-675/655/635 (A/B/C)
Primary Air Duct to Plenum	Flow, klb/hr	BN-43-FI-630/650/670
Total FW Fuel Feed PA (Transport Air)	Flow, klb/hr	BN-34-FI-623/625
Primary Air to SC A	Flow, klb/hr	2S_CAHTPA_FL 2S_CACLR12_FL 2S_CACLR3_FL
Primary Air to SC B	Flow, klb/hr	2S_CBHTPA_FL 2S_CBCLR12_FL 2S_CBCLR3_FL
Primary Air to SC C	Flow, klb/hr	2S_ CCHTPA_FL 2S_CCCLR12_FL 2S_CCCLR3_FL
Primary Air to SC D	Flow, klb/hr	2S_CDHTPA_FL 2S_CDCLR12_FL 2S_CDCLR3_FL
PA Flow to Intrex A	Flow, klb/hr	SI-34-FT-870/878
PA Flow to Intrex B	Flow, klb/hr	SI-34-FT-770/778
PA Flow to Intrex C	Flow, klb/hr	SI-34-FT-670/678
Seal Pot Blower Air Flow to Intrex A	Flow, klb/hr	SI-34-FT-856/840/843/846

Table F-3

DCS Information

Substance	**Characteristic being Measured**	**Instrument Tag #, Remark**
Seal Pot Blower Air Flow to Intrex B	Flow, klb/hr	SI-34-FT-756/740/743/746
Seal Pot Blower Air Flow to Intrex C	Flow, klb/hr	SI-34-FT-656/640/643/646
Intrex Blower Air Flow to Intrex A	Flow, klb/hr	SI-34-FT-816/800
Intrex Blower Air Flow to Intrex B	Flow, klb/hr	SI-34-FT-716/700
Intrex Blower Air Flow to Intrex C	Flow, klb/hr	SI-34-FT-616/600
Furnace Plenum	Pressure, psig	BN-34-PT-520/521/522
Primary Air Fan Outlet	Pressure, psig	BN-34-PT-719/619 (A/B)
Primary Air Heater Air Outlet	Temperature, °F	BN-34-TE-721/621 (A/B)
Total SA	Flow, klb/hr	BN-34-FI-521/571
Lower Overfire Air FW	Flow, klb/hr	BN-34-FI-533/589
Upper Overfire Air FW	Flow, klb/hr	BN-34-FI-539/583
Lower Overfire Air RW	Flow, klb/hr	BN-34-FI-527/577
SA Fan Outlet	Pressure, in wg	BN-34-PT-569/519 (A/B)
SA Fan Outlet	Temperature, °F	BN-34-TE-569/519 (A/B)
SA Airheater Air Out	Temperature, °F	BN-34-TE-571/521 (A/B)
Inlet Vane A	Position, %	SI-34-ZT-570

Table F-3 **DCS Information**		
Substance	**Characteristic being Measured**	**Instrument Tag #, Remark**
Inlet Vane B	Position, %	SI-34-ZT-550
Inlet Vane C	Position, %	SI-34-ZT-530
Intrex Blower Air at Manifold	Pressure, in wg	SI-34-PT-590
	Temperature, °F	SI-34-TE-590
Seal Pot Blower A	Run Status: On = 1 Off = 0	SI-03-008-52A
Seal Pot Blower B	Run Status: On = 1 Off = 0	SI-03-007-52A
Seal Pot Blower C	Run Status: On = 1 Off = 0	SI-03-006-52A
Seal Pot Blower Air at Manifold	Pressure, in wg	SI-34-PT-590
	Temperature, °F	SI-34-TE-960
Damping Valve	Position, %	SI-34-ZT-960
Limestone Feed Rate 1	Flow, klb/hr	2RN-53-010-RATE
Limestone Feed Rate 2	Flow, klb/hr	2RN-53-011-RATE
Limestone Feed Rate 3	Flow, klb/hr	2RN-53-012-RATE
Limestone Composition	As Fired, % Mass	Laboratory Analysis of Limestone Samples Obtained by Grab Sampling
Carbonate Conversion	Fraction	Laboratory Analysis of Limestone Samples Obtained by Grab Sampling
Total Limestone	Flow, klb/hr	2TOTALLIME

Table F-3

DCS Information

Substance	**Characteristic being Measured**	**Instrument Tag #, Remark**
Furnace Freeboard	Pressure Differential, in wg	BB-34-PT-422/472/482
Furnace Exit	Pressure, in wg	BB-34-PT-424/425/426
Cyclone A Gas Inlet	Temperature, °F	SK-34-TE-490/491
Cyclone B Gas Inlet	Temperature, °F	SK-34-TE-470/471
Cyclone C Gas Inlet	Temperature, °F	SK-34-TE-450/451
Cyclone A Gas Discharge	Temperature, °F	SK-34-TE-492
Cyclone B Gas Discharge	Temperature, °F	SK-34-TE-472
Cyclone C Gas Discharge	Temperature, °F	SK-34-TE-452
SDA Hopper	Temperature, °F	RA-34-TE-582
SDA Hopper Differential	Temperature, °F	2TDI-582
Recycle Slurry Mix Tank	Level, %	RA-34-LT-601
Recycle Slurry Storage Tank	Level, %	RA-34-LT-701
Recycle Mix Tank Lime Slurry	Flow, GPM	RL-34-FT-545
Heater Recycle Water	Flow, GPM	RL-34-FT-920
Recycle Slurry	Density, lb/ft^3	RA-34-DT-630
Lime Slurry to Feed Slurry Transfer Pump	Flow, GPM	RA-34-FT-535

Table F-3
DCS Information

Substance	Characteristic being Measured	Instrument Tag #, Remark
SDA Feed Slurry	Flow, GPM	RA-34-FT-530
Fabric Filter Differential	Pressure, in wg	2PDI504-OUTL
SDA Differential	Pressure, in wg	2PDI504-INL
Condensate Cooling	Water Temp to Stripper Cooler, °F	HF34-TE-607
Condensate Cooling Water Outlet Temp	Stripper Cooler A, °F	HF34-TE-606
	Stripper Cooler B, °F	HF34-TE-616
	Stripper Cooler C, °F	HF34-TE-611
	Stripper Cooler D, °F	HF34-TE-601
Condensate Cooling Water Flow	To Stripper Coolers, gpm	HF34-FT-004

Attachment G

Fuel Sample Log and Instructions

Fuel Sample Label	JEA NORTHSIDE GENERATING STATION 4377 HECKSCHER DRIVE JACKSONVILLE, FL 32226-3099 (904) 665-6604 (ph) (904) 665-4895 (fax)		
Test:			
Date:			
Time:			
Sample Type: (Circle One)	**Coke**	or	**Coal**
Sample Taken By:			
Sample Number:			

Sample numbers shall be assigned as follows:

Sample Type – Date - Time - Unit/Feeder - Sample Portion

Sample Type:	C - Coal	PC - Petroleum Coke

Date - Enter the Date without slashes, ie 4/10/02 as 41002

Time - Enter Military Time without the colon, ie 18:30 as 1830

Unit	1 - Unit #1	2 - Unit #2

Feeder - The specific feeder where the sample was obtained

Sample Portion:	= L for the 1 gallon sample to be sent to the lab	= R for the 1 gallon sample to be retained

Example: Petroleum Coke at 8:00 AM on 4/10/02 from Unit #2 B1 Gravimetric Feeder sent to Lab would be Sample Number: PC-41002-0800-2B1-L

Attachment H

Limestone Sample Log and Instructions

Limestone Sample Label	JEA NORTHSIDE GENERATING STATION 4377 HECKSCHER DRIVE JACKSONVILLE, FL 32226-3099 (904) 665-6604 (ph) (904) 665-4895 (fax)
Test:	
Date:	
Time:	
Sample Type	**Limestone**
Sample Taken By:	
Sample Number:	

Sample numbers shall be assigned as follows:

Sample Type - Date - Time - Unit/Feeder - Sample Portion

Sample Type LS - Limestone

Date - Enter the Date without slashes, i.e. 4/10/02 as 41002

Time - Enter Military Time without the colon, i.e. 18:30 as 1830

Unit 1 - Unit #1 2 - Unit #2

Feeder - The specific feeder where the sample was obtained

Sample Portion: = L for the 1 gallon sample to be sent to the lab = R for the 1 gallon sample to be retained

Example: Limestone at 10:00 AM on 4/10/02 from Unit #1 B Rotary Airlock Feeder sent to Lab would be Sample Number: LS-41002-1000-1B-L

Attachment I

Bed Ash Sample Log and Instructions

Bed Ash Sample Label	JEA NORTHSIDE GENERATING STATION 4377 HECKSCHER DRIVE JACKSONVILLE, FL 32226-3099 (904) 665-6604 (ph) (904) 665-4895 (fax)
Test:	
Date:	
Time:	
Sample Type:	**Bed Ash**
Sample Taken By:	
Sample Number:	

Sample numbers shall be assigned as follows:

Sample Type - Date - Time - Unit/Feeder - Sample Portion

Sample Type	BA - Bed Ash	
Date - Enter the Date without slashes, i.e. 4/10/02 as 41002		
Time - Enter Military Time without the colon, i.e. 18:30 as 1830		
Unit	1 - Unit #1	2 - Unit #2
Feeder - The specific feeder where the sample was obtained		
Sample Portion:	= L for the 1 gallon sample to be sent to the lab	= R for the 1 gallon sample to be retained

Example: Bed Ash at 8:00 AM on 4/10/02 from Unit #2 Stripper Cooler D Rotary Valve sent to Lab would be Sample Number: BA-41002-0800-2D-L

Attachment J

Fly Ash Sample Log and Instructions

Fly Ash Sample Label	JEA NORTHSIDE GENERATING STATION 4377 HECKSCHER DRIVE JACKSONVILLE, FL 32226-3099 (904) 665-6604 (ph) (904) 665-4895 (fax)
Test:	
Date:	
Time:	
Sample Type	**Fly Ash**
Sample Taken By:	
Sample Number:	

Sample numbers shall be assigned as follows:

Sample Type - Date - Time - Unit/Feeder - Sample Portion

Sample Type FA - Fly Ash

Date - Enter the Date without slashes, i.e. 4/10/02 as 41002

Time - Enter Military Time without the colon, i.e. 18:30 as 1830

Unit 1 - Unit #1 2 - Unit #2

Feeder - The specific feeder where the sample was obtained

Sample Portion: =L for the 1 gallon sample to be sent to the lab = R for the 1 gallon sample to be retained

Example: Fly Ash at 8:00 AM on 4/10/02 from Unit #2 SDA Inlet sent to Lab would be Sample Number: FA-41002-0800-SDAIN-L

Attachment K

Lime Sample Log and Instructions

Lime Sample Label	JEA NORTHSIDE GENERATING STATION 4377 HECKSCHER DRIVE JACKSONVILLE, FL 32226-3099 (904) 665-6604 (ph) (904) 665-4895 (fax)
Test:	
Date:	
Time:	
Sample Type:	**Lime**
Sample Taken By:	
Sample Number:	

Sample numbers shall be assigned as follows:

Sample Type - Date - Time - Unit/Feeder - Sample Portion

Sample Type L - Lime

Date - Enter the Date without slashes, i.e. 4/10/02 as 41002

Time - Enter Military Time without the colon, i.e. 18:30 as 1830

Unit 1 - Unit #1 2 - Unit #2

Feeder - The specific feeder where the sample was obtained

Sample Portion: =L for the samples to be sent to the lab = R for the samples to be retained

Example: Lime at 8:00 AM on 4/10/02 from Unit #2 SDA Inlet sent to Lab would be Sample Number: L-41002-0800-SDAIN-L

Attachment L

Check List for Fuel Analysis

CHECK LIST FOR FUEL ANALYSIS
PRELIMINARY SUBSTANTIAL COMPLETION TEST

1. GENERAL INFORMATION

Project: ________________________________

Requestor/Phone: ________________ / ________________

Sample ID: ________________________________

Date: ________________________________

Description: ________________________________

2. STANDARD ANALYSES ON EACH COMPOSITE SAMPLE

The feeder samples shall be composited in the laboratory to form a composite sample for each sampling period. The following analyses shall be done on each composite sample, for each sampling period.

2.1 (X) Proximate Analysis (ASTM D3172)
(Moisture, Ash, Volatile, Fixed Carbon, Sulfur)

2.2 (X) Ultimate Analysis (ASTM D3176)
(Carbon, Hydrogen, Nitrogen, Oxygen)

2.3 (X) Heating Value (HHV) (ASTM D1989)

(X) Use benzoic acid at 1:1 in accordance with ASTM D3286, if HHV < 10,000 Btu/lb

2.4 (X) Size Distribution (ASTM D4749) - Dry Basis/Wet Method
(% passing through 1/2", 1/4", #4, #8, #14, #28, #48, #100 Tyler Mesh)

2.5 (X) Analysis of Ash (ASTM D3682)
(Vanadium, Nickel, Iron, SiO_2, K_2O, MgO, Fe_2O_2, SO_3)

2.6 (X) Acetic Acid Soluble Alkalies (Na and K)

2.7 (X) Chlorine (Cl) (ASTM D4208)

2.8 (X) Fluorine (Fl) (ASTM D3761)

2.9 (X) Mercury (Hg) (ASTM D3684)

2.10 (X) Lead (Pb) (ASTM D3683)

Attachment M

Check List for Limestone Analysis

CHECK LIST FOR LIMESTONE ANALYSIS
PRELIMINARY SUBSTANTIAL COMPLETION TEST

1. GENERAL INFORMATION

Project: ______________________________

Requestor/Phone: ______________ / ______________

Sample ID: ______________________________

Date: ______________________________

Description: ______________________________

2. STANDARD ANALYSES ON EACH COMPOSITE SAMPLE

The feeder samples shall be composited in the laboratory to form a composite sample for each sampling period. The following analyses shall be done on each composite sample, for each sampling period.

2.1 (X) % By Weight $CaCO_3$ (ASTM D4326)

2.2 (X) % By Weight $MgCO_3$ (ASTM D4326)

2.3 (X) % By Weight Moisture - By oven drying to constant weight

2.4 (X) % By Weight Inerts - By difference

2.5 (X) Size Distribution (ASTM D4749) Wet/Dry Sieve
(#8, #14, #28, #48, #100, #200, #270 Tyler Mesh)

2.6 (X) Deleted

2.7 (X) Fluorine (Fl) (ASTM D3671)

2.8 (X) Mercury (Hg) (ASTM D3684)

2.9 (X) Lead (Pb) (ASTM D3683)

3. STANDARD ANALYSES ON COMPOSITE TEST SAMPLE

A one-gallon portion of the composite sample for each two-hour time period shall be forwarded to Foster Wheeler's laboratories for testing as follows:

3.1 (X) TGA Reactivity index

Attachment N

Check List for Bed Ash Analysis

CHECK LIST FOR BED ASH ANALYSIS
PRELIMINARY SUBSTANTIAL COMPLETION TEST

1. GENERAL INFORMATION

Project: ____________________

Requestor/Phone: __________ / __________

Sample ID: ____________________

Date: ____________________

Description: ____________________

2. STANDARD ANALYSES ON EACH COMPOSITE SAMPLE (DRY BASIS)

2.1 (X) Total Carbon (% By Weight) using LECO CHN 600 Analyzer (or equal) according to ASTM D3178. See Attachment R for a detailed description.

2.2 (X) Organic Carbon (% By Weight) using HCl treated sample and LECO CHN 600 Analyzer (or equal) according to ASTM D3178. See Attachment R for a detailed description.

2.3 (X) Total Calcium (% By Weight) (ASTM D3682)

2.4 (X) Total Sulfur (% By Weight) (ASTM D4239)

2.5 (X) Size Distribution by Sieve Analysis.
(1/2", 1/4", #4, #8, #14, #28, #48, #100, #200, Tyler Mesh)

2.6 (X) Bulk Density (lb/ft^3)

Attachment O

Check List for Fly Ash Analysis

CHECK LIST FOR FLY ASH ANALYSIS
PRELIMINARY SUBSTANTIAL COMPLETION TEST

1. GENERAL INFORMATION

Project: ______________________________

Requestor/Phone: ______________ / ______________

Sample ID: ______________________________

Date: ______________________________

Description: ______________________________

2. STANDARD ANALYSES ON EACH COMPOSITE SAMPLE (DRY BASIS)

2.1 (X) Total Carbon (% By Weight) using LECO CHN 600 Analyzer (or equal) according to ASTM D3178. See Attachment R for a detailed description.

2.2 (X) Organic Carbon (% By Weight) using HCl treated sample and LECO CHN 600 Analyzer (or equal) according to ASTM D3178. See Attachment R for a detailed description.

2.3 (X) Total Calcium (% By Weight) (ASTM D3682)

2.4 (X) Total Sulfur (% By Weight) (ASTM D4239)

2.5 (X) Size Distribution by Sieve Analysis.
(#4, #14, #28, #48, #100, #270, #325 Tyler Mesh)

2.6 (X) Bulk Density (lb/ft^3)

2.7 (X) Available Ca (% By Weight)

Attachment P

Check List for Lime Analysis

CHECK LIST FOR LIME ANALYSIS
PRELIMINARY SUBSTANTIAL COMPLETION TEST

1. GENERAL INFORMATION

Project: ______________________________

Requestor/Phone: ______________ / ______________

Sample ID: ______________________________

Date: ______________________________

Description: ______________________________

2. STANDARD ANALYSES ON EACH COMPOSITE SAMPLE

The feeder samples shall be composited in the laboratory to form a composite sample for each sampling period. The following analyses shall be done on each composite sample, for each sampling period.

2.1 (X) % By Weight $CaCO_3$ (ASTM D4326)

2.2 (X) % By Weight $MgCO_3$ (ASTM D4326)

2.3 (X) % By Weight Total Solids - By oven drying to constant weight

2.4 (X) % By Weight Inerts - By difference

2.5 (X) Fluorine (Fl) (ASTM D3671)

2.6 (X) Mercury (Hg) (ASTM D3684)

2.7 (X) Lead (Pb) (ASTM D3683)

Attachment Q

Incoming/Outgoing Sample Log Sheets

JEA LARGE-SCALE CFB COMBUSTION DEMONSTRATION PROJECT
FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL
BED ASH SAMPLE LOG SHEET

JANUARY 12-16, 2004

SAMPLE NUMBER	TEST ID	SAMPLE TAKEN BY	DATE TO LAB/STORAGE		ANALYSIS RECEIVED FROM LAB (DATE)	COMMENTS
			LAB	STORAGE		
BA – 041002 – 0800 – 2 B - L						

(2) ONE-GALLON SAMPLES OF BED ASH TO BE TAKEN AT 100% LOAD TEST ONLY
AT START OF THE TEST AND AT THE START OF EACH HOUR OF THE TEST.

STRIPPER COOLER B

JEA LARGE-SCALE CFB COMBUSTION DEMONSTRATION PROJECT
FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL
BED ASH SAMPLE LOG SHEET

JANUARY 12-16, 2004

SAMPLE NUMBER	TEST ID	SAMPLE TAKEN BY	DATE TO LAB/STORAGE		ANALYSIS RECEIVED FROM LAB (DATE)	COMMENTS
			LAB	STORAGE		
BA – 041002 – 0800 – 2 C - L						

(2) ONE-GALLON SAMPLES OF BED ASH TO BE TAKEN AT 100% LOAD TEST ONLY
AT START OF THE TEST AND AT THE START OF EACH HOUR OF THE TEST.

page 1 of 1
STRIPPER COOLER C

JEA LARGE-SCALE CFB COMBUSTION DEMONSTRATION PROJECT
FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL
BED ASH SAMPLE LOG SHEET

JANUARY 12-16, 2004

SAMPLE NUMBER	TEST ID	SAMPLE TAKEN BY	DATE TO LAB/STORAGE		ANALYSIS RECEIVED FROM LAB (DATE)	COMMENTS
			LAB	STORAGE		
BA – 041002 – 0800 – 2 D - L						

(2) ONE-GALLON SAMPLES OF BED ASH TO BE TAKEN AT 100% LOAD TEST ONLY AT START OF THE TEST AND AT THE START OF EACH HOUR OF THE TEST.

page 1 of 1
STRIPPER COOLER D

JEA LARGE-SCALE CFB COMBUSTION DEMONSTRATION PROJECT
FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL
FLY ASH SAMPLE LOG SHEET

JANUARY 12-16, 2004

SAMPLE NUMBER	TEST ID	SAMPLE TAKEN BY	DATE TO LAB/STORAGE		ANALYSIS RECEIVED FROM LAB (DATE)	COMMENTS
			LAB	STORAGE		
FA – 041002 – 0800 – SDA IN - L						

SAMPLES TAKEN PER ARTICLE 907 OF THE TEST PROTOCOL.

JEA LARGE-SCALE CFB COMBUSTION DEMONSTRATION PROJECT
FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL
FLY ASH SAMPLE LOG SHEET

JANUARY 12-16, 2004

SAMPLE NUMBER	TEST ID	SAMPLE TAKEN BY	DATE TO LAB/STORAGE		ANALYSIS RECEIVED FROM LAB (DATE)	COMMENTS
			LAB	STORAGE		
FA – 041002 – 0800 – AH HPR - L						

SAMPLES TAKEN PER ARTICLE 907 OF THE TEST PROTOCOL.

JEA LARGE-SCALE CFB COMBUSTION DEMONSTRATION PROJECT
FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL
FLY ASH SAMPLE LOG SHEET

JANUARY 12-16, 2004

SAMPLE NUMBER	**TEST ID**	**SAMPLE TAKEN BY**	**DATE TO LAB/STORAGE**		**ANALYSIS RECEIVED FROM LAB (DATE)**	**COMMENTS**
			LAB	**STORAGE**		
FA – 041002 – 0800 – FF HPR - L						

SAMPLES TAKEN PER ARTICLE 907 OF THE TEST PROTOCOL.

JEA LARGE-SCALE CFB COMBUSTION DEMONSTRATION PROJECT
FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL
FUEL SAMPLE LOG SHEET

JANUARY 12-16, 2004

SAMPLE NUMBER	TEST ID	SAMPLE TAKEN BY	DATE TO LAB/STORAGE		ANALYSIS RECEIVED FROM LAB (DATE)	COMMENTS
			LAB	STORAGE		
C – 041002 – 0800 – 2 C1 – L						

(2) ONE-GALLON FUEL SAMPLES TAKEN AT 100% LOAD TEST ONLY
AT START OF THE TEST AND AT THE START OF EACH HOUR OF THE TEST.

page 1 of 1
FEEDER C1

JEA LARGE-SCALE CFB COMBUSTION DEMONSTRATION PROJECT
FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL
FUEL SAMPLE LOG SHEET

JANUARY 12-16, 2004

SAMPLE NUMBER	TEST ID	SAMPLE TAKEN BY	DATE TO LAB/STORAGE		ANALYSIS RECEIVED FROM LAB (DATE)	COMMENTS
			LAB	STORAGE		
C – 041002 – 0800 – 2 C2 – L						

(2) ONE-GALLON FUEL SAMPLES TAKEN AT 100% LOAD TEST ONLY
AT START OF THE TEST AND AT THE START OF EACH HOUR OF THE TEST.

FEEDER C2

JEA LARGE-SCALE CFB COMBUSTION DEMONSTRATION PROJECT
FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL
FUEL SAMPLE LOG SHEET

JANUARY 12-16, 2004

SAMPLE NUMBER	TEST ID	SAMPLE TAKEN BY	DATE TO LAB/STORAGE		ANALYSIS RECEIVED FROM LAB (DATE)	COMMENTS
			LAB	STORAGE		
C – 041002 – 0800 – 2 D1 – L						

(2) ONE-GALLON FUEL SAMPLES TAKEN AT 100% LOAD TEST ONLY
AT START OF THE TEST AND AT THE START OF EACH HOUR OF THE TEST.

FEEDER D1

JEA LARGE-SCALE CFB COMBUSTION DEMONSTRATION PROJECT
FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL
FUEL SAMPLE LOG SHEET

JANUARY 12-16, 2004

SAMPLE NUMBER	TEST ID	SAMPLE TAKEN BY	DATE TO LAB/STORAGE		ANALYSIS RECEIVED FROM LAB (DATE)	COMMENTS
			LAB	STORAGE		
C – 041002 – 0800 - 2 D2 – L						

(2) ONE-GALLON FUEL SAMPLES TAKEN AT 100% LOAD TEST ONLY
AT START OF THE TEST AND AT THE START OF EACH HOUR OF THE TEST.

FEEDER D2

JEA LARGE-SCALE CFB COMBUSTION DEMONSTRATION PROJECT
FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL
FUEL SAMPLE LOG SHEET

JANUARY 12-16, 2004

SAMPLE NUMBER	TEST ID	SAMPLE TAKEN BY	DATE TO LAB/STORAGE		ANALYSIS RECEIVED FROM LAB (DATE)	COMMENTS
			LAB	STORAGE		
C – 041002 – 0800 – 2 E1 – L						

(2) ONE-GALLON FUEL SAMPLES TAKEN AT 100% LOAD TEST ONLY
AT START OF THE TEST AND AT THE START OF EACH HOUR OF THE TEST.

FEEDER E1

JEA LARGE-SCALE CFB COMBUSTION DEMONSTRATION PROJECT
FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL
LIME SAMPLE LOG SHEET

JANUARY 12-16, 2004

SAMPLE NUMBER	TEST ID	SAMPLE TAKEN BY	DATE TO LAB/STORAGE		ANALYSIS RECEIVED FROM LAB (DATE)	COMMENTS
			LAB	STORAGE		
L - 041002 - 0800 - SDA IN - L						

(2) ONE-GALLON LIME SLURRY SAMPLES TAKEN AT 100% LOAD TEST ONLY
AT START OF THE TEST AND AT THE START OF EACH HOUR OF THE TEST.

JEA LARGE-SCALE CFB COMBUSTION DEMONSTRATION PROJECT
FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL
LIMESTONE SAMPLE LOG SHEET

JANUARY 12-16, 2004

SAMPLE NUMBER	TEST ID	SAMPLE TAKEN BY	DATE TO LAB/STORAGE		ANALYSIS RECEIVED FROM LAB (DATE)	COMMENTS
			LAB	STORAGE		
LS – 041002 – 0800 – 2 A – L						

(2) ONE-GALLON LIMESTONE SAMPLES TAKEN AT 100% LOAD TEST ONLY
AT START OF THE TEST AND AT THE START OF EACH HOUR OF THE TEST.

FEEDER A

JEA LARGE-SCALE CFB COMBUSTION DEMONSTRATION PROJECT
FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL
LIMESTONE SAMPLE LOG SHEET

JANUARY 12-16, 2004

SAMPLE NUMBER	TEST ID	SAMPLE TAKEN BY	DATE TO LAB/STORAGE		ANALYSIS RECEIVED FROM LAB (DATE)	COMMENTS
			LAB	STORAGE		
LS – 041002 – 0800 – 2 B – L						

(2) ONE-GALLON LIMESTONE SAMPLES TAKEN AT 100% LOAD TEST ONLY
AT START OF THE TEST AND AT THE START OF EACH HOUR OF THE TEST.

FEEDER B

JEA LARGE-SCALE CFB COMBUSTION DEMONSTRATION PROJECT
FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL
LIMESTONE SAMPLE LOG SHEET

JANUARY 12-16, 2004

SAMPLE NUMBER	TEST ID	SAMPLE TAKEN BY	DATE TO LAB/STORAGE		ANALYSIS RECEIVED FROM LAB (DATE)	COMMENTS
			LAB	STORAGE		
LS – 041002 – 0800 – 2 C – L						

(2) ONE-GALLON LIMESTONE SAMPLES TAKEN AT 100% LOAD TEST ONLY
AT START OF THE TEST AND AT THE START OF EACH HOUR OF THE TEST.

FEEDER C

Attachment R

Description of Organic and Inorganic Carbon Analysis Method

Efficient combustion of fuel results normally in very low percentage of carbon content in the fly ash and bottom ash. The sorbent introduces a certain percentage of carbonate carbon in the ash samples. A preferred method of reliably measuring the organic and inorganic carbon in the ash samples is described below:

Total Carbon (Ct)

Use Leco CHN 600 or equivalent analyzer to find the total carbon in the sample.

Organic Carbon

Treat the ash sample with hydrochloric acid to remove the carbonate carbon and use Leco CHN 600 or equivalent analyzer to measure the remaining organic carbon, as described below:

- Weigh 5 grams of sample into a decanter
- First add 200 ml of distilled water and then add 20 ml of concentrated HCl. Cover the decanter.
- Keep the sample on a heating plate for at least two (2) hours. Stir the sample a few times.
- Weigh a membrane filter (pore size 1.2 micron) and a suitable dish for drying the filter.
- Filter the sample under partial vacuum and wash well with distilled water.
- Dry at 105^{o}C the filtered residue with membrane filter.
- Cool in a desiccators and weigh.
- Use Leco CHN 600 or equivalent analyzer to measure (organic) carbon.

$$C_o = \frac{C_{\%} * W_s}{W_o}$$

Where:

C_o = Organic carbon in the ash sample (dry basis).
$C_{\%}$ = Carbon content in the HCl treated sample.
W_s = Weight of HCl treated and dried residue.
W_o = Original weight of sample before HCl treatment.

Inorganic Carbon

$$C_{IC} = C_T - C_o$$

Where:

C_{IC} = Inorganic carbon in the ash sample (dry basis).
C_T = Total carbon in the ash sample.
C_o = Organic carbon in the ash sample.

Attachment S

Boiler Efficiency Sample Calculation

JEA
Unit Tested: Northside Unit 2
Test Date:
Test Start Time:
Test End Time:
Test Duration, hours: 1

Enter all data required in Section 1 - Note: Some cells are identified as calculated values
DO NOT enter values in these cells, imbedded formulas calculate values.
Enter an assumed value for bottom ash flow in cell B52 - recommend a value of XXX
Enter an assumed value for coal flow in cell B159 - recommend a value of XXXXXX.
Enter an assumed value for sulfur emissions in cell B161 - recommend a value of 0.15 - Note: Assumed value must be less than 1.
Enter an assumed value for the calcium to sulfur ratio in cell B181 - recommend a value of 2.5.
Enter an assumed value for excess air leaving the air heater in cell B214 - recommend a value of 20.
Enter an assumed value for excess air entering the air heater in cell B284 - recommend a value of 20.
Enter an assumed value for the excess air at the CEM sample extraction location in cell B252 - recommend a value of 20.
Iterate the calculation to achieve closure using iteration macro - press "Ctrl a" at least FIVE times.

DATA INPUT SECTION - INPUT ALL DATA REQUESTED IN SECTION 1 EXCEPT AS NOTED

1. DATA REQUIRED FOR BOILER EFFICIENCY DETERMINATION

		AS - TESTED Average Value	Units	Symbol
1.1 Fuel				
1.1.1	Feed Rate, lb/h	497,646	lb/h	Wfe - Summation feeder feed rates - FN-34-FT-508, 528, 548, 568, 588, 608, 628, 668
	Composition ("as fired")			
1.1.2	Carbon, fraction	0.6066	lb/lb AF fuel	Cf - Laboratory analysis of coal samples obtained by grab
1.1.3	Hydrogen, fraction	0.0444	lb/lb AF fuel	Hf - Laboratory analysis of coal samples obtained by grab
1.1.4	Oxygen, fraction	0.0663	lb/lb AF fuel	Of - Laboratory analysis of coal samples obtained by grab
1.1.5	Nitrogen, fraction	0.0120	lb/lb AF fuel	Nf - Laboratory analysis of coal samples obtained by grab
1.1.6	Sulfur, fraction	0.0244	lb/lb AF fuel	Sf - Laboratory analysis of coal samples obtained by grab
1.1.7	Ash, fraction	0.1118	lb/lb AF fuel	Af - Laboratory analysis of coal samples obtained by grab
1.1.8	Moisture, fraction	0.1346	lb/lb AF fuel	H2Of - Laboratory analysis of coal samples obtained by
1.1.9	Calcium, fraction	0.0000	lb/lb AF fuel	Caf - Laboratory analysis of coal samples obtained by grab sampling - assume a value of zero if not reported.
1.1.10	HHV	10,944	Btu/lb	HHV - Laboratory analysis of coal samples obtained by
1.2 Limestone				
1.2.1	Feed Rate, lb/h	100,524	lb/h	Wle - Summation feeder feed rates - 2RN-53-010-Rate,
	Composition ("as fired")			
1.2.2	CaCO3, fraction	0.9403	lb/lb limestone	CaCO3l - Laboratory analysis of limestone samples
1.2.3	MgCO3, fraction	0.0126	lb/lb limestone	MgCO3l - Laboratory analysis of limestone samples
1.2.4	Inerts, fraction	0.0465	lb/lb limestone	Il - Laboratory analysis of limestone samples obtained by
1.2.5	Moisture, fraction	0.0006	lb/lb limestone	H2Ol - Laboratory analysis of limestone samples obtained
1.2.6	Carbonate Conversion, fraction	0.95		XCO2 - Laboratory analysis of limestone samples obtained by grab sampling - assume value of 1 if not
1.3 Bottom Ash				
1.3.1	Temperature, °F at envelope	1499	°F	tba - Plant instrument.
	Composition			
1.3.2	Organic Carbon, wt fraction	0.0015	lb/lb BA	Cbao - Laboratory analysis of bottom ash samples
1.3.3	Inorganic Carbon, wt fraction	0.0015	lb/lb BA	Cbaio - Laboratory analysis of bottom ash samples
1.3.4	Total Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0029	lb/lb BA	Cba = Cbao + Cbaio
1.3.5	Calcium, wt fraction	0.1166	lb/lb BA	Caba - Laboratory analysis of bottom ash samples
1.3.6	Carbonate as CO2, wt fraction	0.0015	lb/lb BA	CO2ba - Laboratory analysis of bottom ash samples
1.3.7	Bottom Ash Flow By Iterative Calculation - ENTER ASSUMED VALUE	85,311	lb/h	Wbae

1.4 Fly Ash				
	Composition			
1.4.1	Organic Carbon, wt fraction	0.1166	lb/lb FA	Cfao - Laboratory analysis of fly ash samples obtained by
1.4.2	Inorganic Carbon, wt fraction	0.0015	lb/lb FA	Cfaio - Laboratory analysis of fly ash samples obtained by
	Carbon, wt fraction - CALCULATED			
1.4.3	VALUE DO NOT ENTER	0.1181	lb/lb FA	Cfa = Cfao + Cfaio
1.4.4	Calcium, wt fraction	0.1166	lb/lb FA	Cafa - Laboratory analysis of fly ash samples obtained by
1.4.5	Carbonate as CO2, wt fraction	0.0015	lb/lb FA	CO2fa - Laboratory analysis of fly ash samples obtained
1.4.6	Fly Ash Flow	14,479	lb/hr	Wfam - Weight of fly ash from isokenetic sample
1.5 Combustion Air				
	Primary Air			
	Hot			
1.5.1	Flow Rate, lb/h	14	lb/h	Wpae - Plant instrument.
1.5.2	Air Heater Inlet Temperature, °F	134	°F	tpa
	Cold			
1.5.3	Flow Rate, lb/h	4	lb/hr	
1..5.4	Fan Outlet Temperature, ^{o}F	134	°F	
	Secondary Air			
1.5.5	Flow Rate, lb/h	1	lb/h	Wsae - Plant instrument.
1.5.6	Air Heater Inlet Temperature, °F	115	°F	tsa
	Intrex Blower			
1.5.7	Flow Rate, lb/h	6	lb/h	Wib - Plant instrument
1.5.8	Blower Outlet Temperature, oF	134	^{o}F	tib
	Seal Pot Blowers			
1.5.9	Flow Rate, lb/h	12	lb/h	Wspb - Plant instrument
1.5.10	Blower Outlet Temperature, oF	115	^{o}F	tspb
1.6 Ambient Conditions				
1.6.1	Ambient dry bulb temperature, °F	94.67	°F	ta
1.6.2	Ambient wet bulb temperature, °F	75.55	°F	tawb
1.6.3	Barometric pressure, inches Hg	29.82278	inches Hg	Patm
1.6.4	Moisture in air, lbH2O/lb dry air	0.0147	lbH2O/lb dry air	Calculated: H2OA - From psychometric chart at temperatures ta and tawb adjusted to test Patm.
1.7 Flue Gas				
	At Air Heater Outlet			
1.7.1	Temperature (measured), °F	322.7529	°F	Tg15 - Weighted average from AH outlet plant instruments (based on PA and SA flow rates) THIS MAY NEED TO BE DETERMINED BY TEST EQUIPMENT
1.7.2	Temperature (unmeasured), °F			Calculated
	Composition (wet)			
1.7.3	O2	0.0558	percent volume	O2 - Weighted average from test instrument, may not have to weight depending on location of probes
1.7.4	CO2	Not Measured	percent volume	CO2
1.7.5	CO	Not Measured	percent volume	CO
1.7.6	SO2	Not Measured	percent volume	SO2
	At Air Heater Inlet			
1.7.7	Temperature, °F	628.22	°F	tG14 - Plant Instrument
	Composition (wet)			
1.7.8	O2	0.0396	percent volume	
1.7.9	CO2	Not Measured	percent volume	
1.7.10	CO	Not Measured	percent volume	
1.7.11	SO2	0.0001	percent volume	measurement is in ppm

	CEM Sample Extraction At Outlet Of Composition			
1.7.12	O_2, percent - WET basis	2.90	percent volume	O2stk
1.7.13	SO_2, ppm - dry basis	114.9	ppm	SO2stk
1.7.14	NO_x, ppm - dry basis	Not Measured	ppm	Noxstk
1.7.15	CO, ppm - dry basis	Not Measured	ppm	Costk
1.7.16	Particulate, mg/Nm³	Not Meausred	mg/Nm³ - 25° C	PARTstk
1.8 Feedwater				
1.8.1	Pressure, psig	2617	psig	pfw - Plant instrument.
1.8.2	Temperature, °F	483	°F	tfw - Plant instrument.
1.8.3	Flow Rate, lb/h	4,059,088	lb/h	FW - Plant instrument.
1.9 Continuous Blow Down				
1.9.1	Pressure, psig (drum pressure)	2,586.08	psig	pbd - Plant instrument
1.9.2	Temperature, °F (sat. temp. @ drum	675.10	°F	tba - Saturated water temperature from steam table at
1.9.3	Flow Rate, lb/h	0.00	lb/h	BD - Estimated using flow characteristic of valve and
1.10 Sootblowing				
1.10.1	Flow Rate, lb/hr	0.00	lb/hr	SB - Plant instrument
1.10.2	Pressure, psig	0.00	psig	psb - Plant instrument
1.10.3	Temperature, F	0.00	F	tsb - plant instrument
1.11 Main Steam Desuperheating Water				
1.11.1	Pressure, psig	2,666.89	psig	pdsw - Plant instrument.
1.11.2	Temperature, °F	404.20	°F	tdsw - Plant instrument.
1.11.3	Flow Rate, lb/h	28,559.18	lb/h	DSW - Plant instrument.
1.12 Main Steam				
1.12.1	Pressure, psig (superheater outlet)	2,463.26	psig	pms - Plant instrument.
1.12.2	Temperature, °F	1,004.76	°F	tms - Plant instrument.
1.12.3	Flow Rate, lb/h	4,087,647	lb/h	MS - Plant instrument - Not required to determine boiler efficiency - For information only.
1.13 Reheat Steam Desuperheating Water				
1.13.1	Pressure, psig	1,000.00	psig	pdswrh - Plant instrument.
1.13.2	Temperature, °F	399.20	°F	tdswrh - Plant instrument.
1.13.3	Flow Rate, lb/h	0.00	lb/h	DSWrh - Plant instrument.
1.14 Reheat Steam				
1.14.1	Inlet Pressure, psig	600.87	psig	prhin - Plant instrument.
1.14.2	Inlet Temperature, °F	647.40	°F	trhin - Plant instrument.
1.14.3	Outlet Pressure, psig	580.29	psig	prhout - Plant instrument.
1.14.4	Outlet Temperature, °F	1,011.31	°F	trhout - Plant instrument.
1.14.5	Inlet Flow, lb/hr	#NAME?	lb/hr	RHin - From turbine heat.

CALCULATION SECTION - ALL VALUES BELOW CALCULATED BY EMBEDDED FORMULAS
DO NOT ENTER DATA BELOW THIS LINE - EXCEPT ASSUMED VALUES FOR ITERATIVE CALCULATIONS

2. REFERENCE TEMPERATURES

2.1 Average Air Heater Inlet Temperature 132.97

3. SULFUR CAPTURE

The calculation of efficiency for a circulating fluid bed steam generator that includes injection of a reactive sorbent material, such as sulfur dioxide emissions is an iterative calculation to minimize the number of parameters that have to be measured and the number of analyses that must be performed. This both reduces the cost of the test and increases the accuracy by minimizing the impact of field instrument inaccuracies.

To begin the process, assume a fuel flow rate. The fuel flow rate is required to complete the material balances necessary to determine limestone used and the effect of the limestone reaction on the boiler efficiency. The resulting boiler efficiency is used to calculate a flow rate. If the calculated flow rate is more than 1 percent different than the assumed flow rate, a new value for fuel flow rate is selected calculation is repeated. This process is repeated until the assumed value for fuel flow and the calculated value for fuel flow differ by less of the value of the calculated fuel flow

3.1	ASSUMED FUEL FLOW RATE, lb/h	471,330	lb/h	
3.2	ASSUMED SULFUR EMISSIONS, fraction	0.0498	fraction	Can get reading from CEMS system
3.3	Sulfur Capture, fraction	0.9502		

4. ASH PRODUCTION AND LIMESTONE CONSUMPTION

4.1	**Accumulation of Bed Inventory**	0	lb/h	
4.2	**Corrected Ash Carbon Content**			
4.2.1	Bottom Ash, fraction	0.0025	lb/lb BA	
4.2.2	Fly Ash, fraction	0.1177	lb/lb FA	
4.3	**Bottom Ash Flow Rate**			
4.3.1	Total bottom ash including bed	#############	lb/h	
4.4	**Limestone Flow Rate**			

Iterate to determine calcium to sulfur ratio and limestone flow rate. Enter an assumed value for the calcium to sulfur ratio. Compare resulting calculated calcium to sulfur ratio to assumed value. Change assumed value until the difference between the assumed value and the calculated value is less than 1 percent of the assumed value.

4.4.1	Assumed Calcium to Sulfur Ratio	0.806582666	mole Ca/mole S	
4.4.2	Solids From Limestone - estimated	1.465477239	lb/lb limestone	al = (CaCO3l * (56.0794/100.08935)) + ((CaCO3l/CaS) * (80.0622/100.08935) * XSO2) + ((40.2114/84.22135) * MgCO3l) + Il
4.4.3	Limestone Flow Rate - estimated	30844.10107	lb/h	Wle = ((Wfea * af * ((Caf - (Cafa/(1 - Cfai)))) + Wbae' * (1 - Cba') * ((Cafa/(1 - Cfa)) - Caba)/((Cafa/(1 - Cfa')) - (0.4 *
4.4.4	Calculated Calcium to Sulfur Ratio	0.806578489	mole Ca/mole S	
4.4.5	Difference Estimated vs Assumed - Ca:S	-0.000517839	percent	
4.4.6	Calculated Fly Ash Flow Rate	14,479	lb/h	
4.4.7	Difference Calculated vs Measured	0.0004917238	percent	
4.5	**Total Dry Refuse**			
4.5.1	Total Dry Refuse Hourly Flow Rate	99,790	lb/h	
4.5.2	Total Dry Refuse Per Pound Fuel	0.2117	lb/lb AF fuel	

4.6 Heating Value Of Total Dry Refuse

4.6.1	Average Carbon Content Of Ash	0.0192	fraction
4.6.2	Heating Value Of Dry Refuse	278.62	Btu/lb

5. HEAT LOSS DUE TO DRY GAS

5.1 Carbon Burned Adjusted For Limestone

5.1.1	Carbon Burned	0.6025	lb/lb AF fuel
5.1.2	Carbon Adjusted For Limestone	0.6096	lb/lb AF fuel

Determine Amount Of Flue Gas

Iterate to determine carbon dioxide volumetric content of dry flue gas. Enter an assumed value for excess air. Compare resulting calculated oxygen content to the measure oxygen content. Change assumed value of excess air until the the calculated oxygen content value and the measured value oxygen content value is less than 1 percent of the assumed value. Use the calculated carbon dioxide value in subsequent calculations.

5.2 Air Heater Outlet

5.2.1	Assumed Excess Air At Air Heater Outlet	35.96820373	percent	
5.2.2	Corrected Stoichiometric O2, lb/lb fuel	1.9211	lb/lb AF fuel	O2stoich = (31.9988/12.01115) * Cb + (15.9994/2.01594) * Hf + (31.9998/32.064) * Sf - Of + (((Sf * 31.9988/32.064) * (XSO2) * 31.9988 * 0.5/64.0128)
5.2.3	Corrected Stoichiometric N2, lb/lb fuel	6.3809	lb/lb AF fuel	
5.2.4	<u>Flue Gas Composition, Weight Basis, lb/lb AF Fuel</u>			
5.2.4.1	Carbon Dioxide, weight fraction	2.2337	lb/lb AF fuel	
5.2.4.2	Sulfur Dioxide, weight fraction	0.0024	lb/lb AF fuel	
5.2.4.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.6794	lb/lb AF fuel	
5.2.4.4	Nitrogen from air, weight fraction	8.6760	lb/lb AF fuel	
5.2.4.5	Nitrogen from fuel, weight fraction	0.0120	lb/lb AF fuel	
5.2.4.6	Moisture from fuel, weight fraction	0.1346	lb/lb AF fuel	
5.2.4.7	Moisture from hydrogen in fuel, weight fraction	0.3964	lb/lb AF fuel	
5.2.4.8	Moisture from limestone, weight fraction	0.0000	lb/lb AF fuel	
5.2.4.9	Moisture from combustion air, weight fraction	<u>0.1657</u>	lb/lb AF fuel	
5.2.5	Weight of DRY Products of Combustion - Air Heater OUTLET	11.6036	lb/lb AF fuel	
5.2.6	Molecular Weight, lb/lb mole DRY FG - Air Heater OUTLET	30.4924	lb/lb mole	MWahoutdry = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134))
5.2.7	Weight of WET Products of Combustion - Air Heater OUTLET	12.3003	lb/lb AF fuel	
5.2.8	Molecular Weight, lb/lb mole WET FG - Air Heater OUTLET	29.3414	lb/lb AF fuel	(SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134) + ((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534))

Note: Molecular weight of nitrogen in air (N2a) is 28.161 lb/lb mole per PTC 4 Sub-Section 5.11.1 to account for trace gases in air.

5.2.9	Dry Flue Gas Composition, Volume Basis, % Dry Flue Gas		
5.2.9.1	Carbon Dioxide, volume percent	13.3378	percent volume
5.2.9.2	Sulfur Dioxide, volume percent	0.0100	percent volume
5.2.9.3	Oxygen from air, volume percent	5.5794	percent volume
5.2.9.4	Nitrogen from air, volume percent	80.9603	percent volume
5.2.9.5	Nitrogen from fuel, volume percent	0.1126	percent volume
		100.0000	percent volume
5.2.10	Oxygen - MEASURED AT AIR HEATER OUTLET, % vol - dry FG	5.579384639	percent
5.2.11	Difference Calculated versus Measured Oxygen At Air Heater Outlet	-2.81809E-06	percent
5.2.12	Carbon Dioxide, DRY vol. fraction	0.1334	
5.2.13	Nitrogen (by difference), DRY vol. fraction	0.8108	
5.2.14	Weight Dry FG At Air Heater	11.5584	lb/lb AF fuel
5.2.15	Molecular Weight Of Dry Flue Gas At Air Heater OUTLET	30.4900	lb/lb mole
5.2.16	Wet Flue Gas Composition, Volume Basis, % Wet Flue Gas		
5.2.16.1	Carbon Dioxide, volume percent	12.1074	percent volume
5.2.16.2	Sulfur Dioxide, volume percent	0.00905	percent volume
5.2.16.3	Oxygen from air, volume percent	5.0647	percent volume
5.2.16.4	Nitrogen from air, volume percent	73.4917	percent volume
5.2.16.5	Nitrogen from fuel, volume percent	0.1022	percent volume
5.2.16.6	Moisture from fuel, fuel hydrogen, limestone, and air	9.2250	percent volume H2O%out = (((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534) * (100)/(Wgcalcahoutwet/MWahoutwet)
		100.0000	
5.2.17	Weight Wet FG At Air Heater	12.2551	lb/lb AF fuel
5.2.18	Molecular Weight Of Wet Flue Gas At Air Heater OUTLET	29.3353	lb/lb mole
5.2.19	Weight Fraction of DRY Flue Gas Components		
5.2.19.1	Oxygen, fraction weight	0.0586	fraction
5.2.19.2	Nitrogen, fraction weight	0.7489	fraction
5.2.19.3	Carbon Dioxide, fraction weight	0.1926	fraction
5.2.19.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.2.19.5	Sulfur Dioxide, fraction weight	0.0000	fraction
5.2.20	Weight Fraction of WET Flue Gas Components		
5.2.20.1	Oxygen, fraction weight	0.0552	fraction
5.2.20.2	Nitrogen, fraction weight	0.7063	fraction
5.2.20.3	Carbon Dioxide, fraction weight	0.1816	fraction
5.2.20.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.2.20.5	Sulfur Dioxide, fraction weight	0.0000	fraction
5.2.20.6	Moisture, fraction weight	0.0567	fraction

5.3 Air Heater Inlet

5.3.1	Assumed Excess Air At Air Heater INLET	23.28818989	percent
5.3.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.3.2.1	Carbon Dioxide, weight fraction	2.2337	lb/lb AF fuel
5.3.2.2	Sulfur Dioxide, weight fraction	0.0024	lb/lb AF fuel
5.3.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.4358	lb/lb AF fuel
5.3.2.4	Nitrogen from air, weight fraction	7.8669	lb/lb AF fuel
5.3.2.5	Nitrogen from fuel, weight fraction	0.0120	lb/lb AF fuel
5.3.2.6	Moisture from fuel, weight fraction	0.1346	lb/lb AF fuel
5.3.2.7	Moisture from hydrogen in fuel, weight fraction	0.3964	lb/lb AF fuel
5.3.2.8	Moisture from limestone, weight fraction	0.0000	lb/lb AF fuel
5.3.2.9	Moisture from combustion air, weight fraction	0.1502	lb/lb AF fuel
5.3.3	Weight of DRY Products of Combustion - Air Heater INLET	10.5509	lb/lb AF fuel
5.3.4	Molecular Weight, lb/lb mole DRY FG - Air Heater INLET	30.6537	lb/lb mole
5.3.5	Weight of WET Products of Combustion - Air Heater INLET	11.2321	lb/lb AF fuel
5.3.6	Molecular Weight, lb/lb mole WET FG - Air Heater INLET	29.4027	lb/lb AF fuel
		Volume Basis	
5.3.7	Flue Gas Composition, Volume Basis, % DRY Flue Gas	% Dry Flue Gas	
5.3.7.1	Carbon Dioxide, volume percent	14.7461	percent volume
5.3.7.2	Sulfur Dioxide, volume percent	0.0110	percent volume
5.3.7.3	Oxygen from air, volume percent	3.9568	percent volume
5.3.7.4	Nitrogen from air, volume percent	81.1616	percent volume
5.3.7.5	Nitrogen from fuel, volume percent	0.1245	percent volume
		100.0000	percent volume
5.3.8	Oxygen - MEASURED AT AIR HEATER INLET, % vol - dry FG	3.956815104	percent
5.3.9	Difference Calculated versus Measured Oxygen At Air Heater Inlet	-8.89245E-06	percent
5.3.10	Carbon Dioxide, DRY vol. fraction	0.1475	
5.3.11	Nitrogen (by difference), DRY vol. fraction	0.8129	
5.3.12	Weight Dry FG At Air Heater INLET	10.5104	lb/lb AF fuel
5.3.13	Molecular Weight Of Dry Flue Gas At Air Heater INLET	30.6556	lb/lb mole

5.3.14	Flue Gas Composition, Volume Basis, % Wet Flue Gas	% Wet Flue Gas	
5.3.14.1	Carbon Dioxide, volume percent	13.2864	percent volume
5.3.14.2	Sulfur Dioxide, volume percent	0.00993	percent volume
5.3.14.3	Oxygen from air, volume percent	3.5651	percent volume
5.3.14.4	Nitrogen from air, volume percent	73.1275	percent volume
5.3.14.5	Nitrogen from fuel, volume percent	0.1121	percent volume
5.3.14.6	Moisture from fuel, fuel hydrogen, limestone, and air	9.8989	percent volume
		100.0000	
5.3.15	Weight Wet FG At Air Heater INLET	11.1916	lb/lb AF fuel
5.3.16	Molecular Weight Of Wet Flue Gas At Air Heater INLET	29.4000	lb/lb mole
5.3.17	Weight Fraction of DRY Flue Gas Components		
5.3.17.1	Oxygen, fraction weight	0.0413	fraction
5.3.17.2	Nitrogen, fraction weight	0.7467	fraction
5.3.17.3	Carbon Dioxide, fraction weight	0.2118	fraction
5.3.17.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.17.5	Sulfur Dioxide, fraction weight	0.0000	fraction
5.3.18	Weight Fraction of WET Flue Gas Components		
5.3.18.1	Oxygen, fraction weight	0.0388	fraction
5.3.18.2	Nitrogen, fraction weight	0.7013	fraction
5.3.18.3	Carbon Dioxide, fraction weight	0.1989	fraction
5.3.18.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.18.5	Sulfur Dioxide, fraction weight	0.0002	fraction
5.3.18.6	Moisture, fraction weight	0.0607	fraction

5.4 CEM Sampling Location

5.4.1	Assumed Excess Air At CEM Sampling Location	18.35712549	percent
5.4.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.4.2.1	Carbon Dioxide, weight fraction	2.2337	lb/lb AF fuel
5.4.2.2	Sulfur Dioxide, weight fraction	0.0024	lb/lb AF fuel
5.4.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.3411	lb/lb AF fuel
5.4.2.4	Nitrogen from air, weight fraction	7.5523	lb/lb AF fuel
5.4.2.5	Nitrogen from fuel, weight fraction	0.0120	lb/lb AF fuel
5.4.2.6	Moisture from fuel, weight fraction	0.1346	lb/lb AF fuel
5.4.2.7	Moisture from hydrogen in fuel, weight fraction	0.3964	lb/lb AF fuel
5.4.2.8	Moisture from limestone, weight fraction	0.0000	lb/lb AF fuel
5.4.2.9	Moisture from combustion air, weight fraction	0.1442	lb/lb AF fuel

5.4.3	Weight of DRY Products of Combustion - CEM Sampling Location	10.1415	lb/lb AF fuel
5.4.4	Molecular Weight, lb/lb mole DRY FG - CEM Sampling Location	30.7261	lb/lb mole
5.4.5	Weight of WET Products of Combustion - CEM Sampling Location	10.8168	lb/lb AF fuel
5.4.6	Molecular Weight, lb/lb mole WET FG - CEM Sampling Location	29.4298	lb/lb mole
5.4.7	Flue Gas Composition, Volume Basis, % WET or DRY Flue Gas	Volume Basis % Wet Flue Gas	
5.4.7.1 a	Carbon Dioxide, volume percent	13.8094	percent volume
5.4.7.2 a	Sulfur Dioxide, volume percent	0.0103	percent volume
5.4.7.3 a	Oxygen from air, volume percent	2.9000	percent volume
5.4.7.4 a	Nitrogen from air, volume percent	72.9659	percent volume
5.4.7.5 a	Nitrogen from fuel, volume percent	0.1165	percent volume
5.4.7.6 a	Moisture in flue gas, voluem percent	10.1978	percent volume
		100.0000	percent volume
		Volume Basis % Dry Flue Gas	
5.4.7.1 b	Carbon Dioxide, volume percent	15.3776	percent volume
5.4.7.2 b	Sulfur Dioxide, volume percent	0.0115	percent volume
5.4.7.3 b	Oxygen from air, volume percent	3.2293	percent volume
5.4.7.4 b	Nitrogen from air, volume percent	81.2518	percent volume
5.4.7.5 b	Nitrogen from fuel, volume percent	0.1298	percent volume
5.4.7.6 b	Moisture in flue gas, voluem percent	0.0000	percent volume
		100.0000	percent volume
5.4.8	Oxygen - MEASURED AT CEM SAMPLING LOCATION, % vol - wet FG	2.9	percent volume
5.4.9	Difference Calculated versus Measured Oxygen At CEM Sample Port In Stack	-7.67162E-05	percent
5.4.10	Sulfur Dioxide - MEASURE AT CEM SAMPLING LOCATION, ppm - dry FG	114.9	ppm
5.4.11	Difference Calculated versus Measure Sulfur Dioxide At CEM	0.000732728	percent

5.5 Determine Loss Due To Dry Gas

5.5.1 Enthalpy Coefficients For Gaseous Mixtures - From PTC 4 Sub-Section 5.19.11

		Oxygen
	C0	-1.1891960E+02
	C1	4.2295190E-01
	C2	-1.6897910E-04
	C3	3.7071740E-07
	C4	-2.7439490E-10
	C5	7.384742E-14
5.5.2 a Flue Gas Constituent Enthalpy At tG15		5.480505E+01
5.5.3 a Flue Gas Constituent Enthalpy At tA8		1.231689E+01
		Nitrogen
	C0	-1.3472300E+02
	C1	4.6872240E-01
	C2	-8.8993190E-05
	C3	1.1982390E-07
	C4	-3.7714980E-11
	C5	-3.5026400E-16
5.5.2 b Flue Gas Constituent Enthalpy At tG15		6.0702869E+01
5.5.3 b Flue Gas Constituent Enthalpy At tA8		1.3794211E+01
		Carbon Dioxide
	C0	-8.5316190E+01
	C1	1.9512780E-01
	C2	3.5498060E-04
	C3	-1.7900110E-07
	C4	4.0682850E-11
	C5	1.0285430E-17
5.5.2 c Flue Gas Constituent Enthalpy At tG15		5.3332024E+01
5.5.3 c Flue Gas Constituent Enthalpy At tA8		1.1505286E+01
		Carbon Monoxide
	C0	-1.3574040E+02
	C1	4.7377220E-01
	C2	-1.0337790E-04
	C3	1.5716920E-07
	C4	-6.4869650E-11
	C5	6.1175980E-15
5.5.2 d Flue Gas Constituent Enthalpy At tG15		6.1360815E+01
5.5.3 d Flue Gas Constituent Enthalpy At tA8		1.3918986E+01

		Sulfur Dioxide		
	C0	-6.7416550E+01		
	C1	1.8238440E-01		
	C2	1.4862490E-04		
	C3	1.2737190E-08		
	C4	-7.3715210E-11		
	C5	2.8576470E-14		
5.5.2 e Flue Gas Constituent Enthalpy At tG15		3.8807190E+01		
5.5.3 e Flue Gas Constituent Enthalpy At tA8		8.4475868E+00		

General equation for constituent enthalpy:
h = C0 + C1 * T + C2 * T² + C3 * T³ + C4 * T * T³ + C5 * T² * T³
T = degrees Kelvin = (°F + 459.7)/1.8

5.5.4	Flue Gas Enthalpy			
5.5.5	At Measured AH Outlet Temp - tG15	58.94	Btu/lb	hFGtG15 = O2wt * hO2 + N2wt * hN2 + C(
5.5.6	At Measured AH Air Inlet Temp - tA8	13.27	Btu/lb	hFGtA8 = O2wt * hO2 + N2wt * hN2 + CO:
5.5.7	Dry Flue Gas Loss, as tested	527.89	Btu/lb AF fuel	
5.6	***HHV Percent Loss, as tested***	4.82	percent	

6. HEAT LOSS DUE TO MOISTURE CONTENT IN FUEL

6.1	Water Vapor Enthalpy at tG15 & 1 psia	1206.04	Btu/lb	hwvtG15 = 0.4329 * tG15 + 3.958E-05 * (t
6.2	Saturated Water Enthalpy at tA8	100.97	Btu/lb	
6.3	Fuel Moisture Heat Loss, as tested	148.70	Btu/lb AF fuel	
6.4	***HHV Percent Loss, as tested***	1.36	percent	

7. HEAT LOSS DUE TO H2O FROM COMBUSTION OF H2 IN FUEL

7.1	H2O From H2 Heat Loss, as tested	438.10	Btu/lb AF fuel
7.2	***HHV Percent Loss, as tested***	4.00	percent

8. HEAT LOSS DUE TO COMBUSTIBLES (UNBURNED CARBON) IN ASH

8.1	Unburned Carbon In Ash Heat Loss	58.99	Btu/lb AF fuel
8.2	***HHV Percent Loss, as tested***	0.54	percent

9. HEAT LOSS DUE TO SENSIBLE HEAT IN TOTAL DRY REFUSE

9.1 Determine Dry Refuse Heat Loss Per Pound Of AF Fuel

9.1.1	Bottom Ash Heat Loss, as tested	61.82	Btu/lb AF fuel
9.1.2	Fly Ash Heat Loss, as tested	1.17	Btu/lb AF fuel
9.2	**Total Dry Refuse Heat Loss, as tested**	62.99	Btu/lb AF fuel
9.3	***HHV Percent Loss, as tested***	0.58	percent

10. HEAT LOSS DUE TO MOISTURE IN ENTERING AIR

10.1 Determine Air Flow

10.1.1	Dry Air Per Pound Of AF Fuel	11.56	lb/lb AF fuel

10.2 Heat Loss Due To Moisture In Entering Air

10.2.1	Enthalpy Of Leaving Water Vapor	160.20	Btu/lb AF fuel
10.2.2	Enthalpy Of Entering Water Vapor	65.32	Btu/lb AF fuel
10.2.3	Air Moisture Heat Loss, as tested	16.09	Btu/lb
10.3	***HHV Percent Loss, as tested***	0.15	percent

11. HEAT LOSS DUE TO LIMESTONE CALCINATION/SULFATION REACTIONS

11.1 Loss To Calcination

11.1.1	Limestone Calcination Heat Loss	45.29	Btu/lb AF Fuel

11.2 Loss To Moisture In Limestone

11.2.1	Limestone Moisture Heat Loss	0.05	Btu/lb AF Fuel

11.3 Loss From Sulfation

11.3.1	Sulfation Heat Loss	-156.35	Btu/lb AF Fuel

11.4 Net Loss To Calcination/Sulfation

11.4.1	Net Limestone Reaction Heat Loss	-111.02	Btu/lb AF Fuel
11.5	***HHV Percent Loss***	-1.01	percent

12. HEAT LOSS DUE TO SURFACE RADIATION & CONVECTION

12.1	***HHV Percent Loss***	#NAME?	percent
12.1.1	Radiation & Convection Heat Loss	#NAME?	Btu/lb AF fuel

13. SUMMARY OF LOSSES - AS TESTED/GUARANTEE BASIS

		As Tested Btu/lb AF Fuel
13.1.1		527.89
13.1.2		148.70
13.1.3		438.10
13.1.4		58.99
13.1.5		62.99
13.1.6		16.09
13.1.7		-111.02
13.1.8		#NAME?
		#NAME?

		As Tested Percent Loss
13.1.9	Dry Flue Gas	4.82
13.1.10	Moisture In Fuel	1.36
13.1.11	H2O From H2 In Fuel	4.00
13.1.12	Unburned Combustibles In Refuse	0.54
13.1.13	Dry Refuse	0.58
13.1.14	Moisture In Combustion Air	0.15
13.1.15	Calcination/Sulfation	-1.01
13.1.16	Radiation & Convection	#NAME?
		#NAME?

13.2 Boiler Efficiency (100 - Total Losses), percent ***#NAME?***

14. HEAT INPUT TO WATER & STEAM

14.1 Enthalpies

14.1.1	Feedwater, Btu/lb	468.37	Btu/lb
14.1.2	Blow Down, Btu/lb	741.19	Btu/lb
14.1.3	Sootblowing, Btu/lb	0.00	Btu/lb
14.1.4	Desuperheating Spray Water - Main Steam, Btu/lb	382.33	Btu/lb
14.1.5	Main Steam, Btu/lb	1462.28	Btu/lb
14.1.6	Desuperheating Spray Water - Reheat Steam, Btu/lb	375.00	Btu/lb
14.1.7	Reheat Steam - Reheater Inlet,	1318.59	Btu/lb
14.1.8	Reheat Steam - Reheater Outlet,	1522.96	Btu/lb

14.2 Heat Output	#NAME?	Btu/h
	#NAME?	

15. HIGHER HEATING VALUE FUEL HEAT INPUT

15.1 Determine Fuel Heat Input Based on Calculated Efficiency

15.1.1	Fuel Heat Input	#NAME?	Btu/h
15.1.2	Fuel Burned - CALCULATED	#NAME?	lb/h
15.1.3	Difference Assumed versus	#NAME?	percent

OUTPUT

Jacksonville Electric Authority
Unit Tested: Northside Unit 2
Test Date:
Test Start Time:
Test End Time:
Test Duration, hours:

Parameter		As-Tested	Units	
1.0 Feedwater				
	1.1 Flow Rate, lb/hr	4,059,088	lb/hr	FW - Plant instrument.
	1.2 Pressure, psig	2,616.9	psig	pfw - Plant instrument.
	1.3 Temperature, F	483.2	F	tfw - Plant instrument.
	1.4 Enthalpy	#NAME?	Btu/lb	hfw - Steam Properties Microcomputer Program - University of Texas at Austin - Center for Energy Studies - September 1981
	1.5 Heat available	#NAME?	Btu/hr	hfw x FW
2.0 Mainsteam Desuperheating				
	2.1 Flow Rate	28,559	lb/hr	DSW - Plant instrument.
	2.2 Pressure	2,666.9	psig	pdsw - Plant instrument.
	2.3 Temperature	404.2	F	tdsw - Plant instrument.
	2.4 Enthalpy	#NAME?	Btu/lb	hdsw - Steam Properties Microcomputer Program - University of Texas at Austin - Center for Energy Studies - September 1981
	2.5 Heat available	#NAME?	Btu/hr	hdsw x DSW
3.0 Continuous Blowdown				
	3.1 Flow Rate	0	lb/h	BD - Estimated using flow characteristic of valve and number of turns open.
	3.2 Pressure	2,586.1	psig	pbd - Plant instrument
	3.3 Temperature	675.1	°F	tba - Saturated water temperature from steam table at drum pressure.
	3.4 Enthalpy	#NAME?	Btu/lb	hcbd - Steam Properties Microcomputer Program - University of Texas at Austin - Center for Energy Studies - September 1981
	3.5 Heat available	#NAME?	Btu/hr	hcbd x BD
4.0 Sootblowing				
	4.1 Flow Rate, lb/hr	0	lb/hr	SB - Plant instrument
	4.2 Pressure, psig	0	psig	psb - Plant instrument
	4.3 Temperature, F	0	F	tsb - plant instrument
	4.4 Enthalpy	0.00	Btu/lb	hsb - Steam Properties Microcomputer Program - University of Texas at Austin - Center for Energy Studies - September 1981
	4.5 Heat available	0	Btu/hr	hsb x SB
5.0 Main Steam				
	5.1 Flow Rate	4,087,647	lb/hr	MS = FW + DSW - CBD - SB
	5.2 Pressure	2,463.26	pisg	pms - Plant instrument.
	5.3 Temperature	1,004.76	°F	tms - Plant instrument.
	5.4 Enthalpy	#NAME?	Btu/lb	hms - Steam Properties Microcomputer Program - University of Texas at Austin - Center for Energy Studies - September 1981
	5.5 Heat available	#NAME?	Btu/hr	hms x MS
6.0 Reheat Desuperheating				
	6.1 Flow Rate	0.00	lb/h	DSWrh - Plant instrument.
	6.2 Pressure	1000.00	psig	pdswrh - Plant instrument.
	6.3 Temperature	399.20	°F	tdswrh - Plant instrument.
	6.4 Enthalpy	#NAME?	Btu/lb	hdswrh - Steam Properties Microcomputer Program - University of Texas at Austin - Center for Energy Studies - September 1981
	6.5 Heat available	#NAME?	Btu/hr	hdswrh x DSWrh

7.0 Heater No. 1 Heat Balance

7.1	Feedwater flow to heaters	4,087,647	lb/hr	FW + DSW + DSWrh
7.2	Feedwater @ Inlet			
7.2.1	Pressure	2,666.9	psig	ph1fwi - Plant instrument.
7.2.2	Temperature	453.2	F	th1fwi - Plant instrument.
7.2.3	Enthalpy	#NAME?	Btu/lb	
7.3	Feedwater @ Outlet			
7.3.1	Pressure	2,616.9	psig	ph1fwo - Plant instrument.
7.3.2	Temperature	483.2	F	th1fwo - Plant instrument.
7.3.3	Enthalpy	#NAME?	Btu/lb	
7.4	Heater Drain			
7.4.1	Pressure	550.9	psig	ph1dr - Plant instrument.
7.4.2	Temperature	497.4	F	th1dr - Plant instrument.
7.4.3	Enthalpy	#NAME?	Btu/lb	
7.5	Turbine Extraction			
7.5.1	Pressure	600.9	psig	ph1ext - Plant instrument.
7.5.2	Temperature	647.4	F	th1ext - Plant instrument.
7.5.3	Enthalpy	#NAME?	Btu/lb	
7.6	Extraction Flow	#NAME?	lb/hr	Ext = heat balance around heater

8.0 Cold Reheat

8.1	TG Leaks	0.00	lb/hr	tgl
8.2	CRH Flow Rate	#NAME?	lb/hr	CRH = MS - tgl - Ext - SB
8.3	Pressure	600.87	psig	prhin - Plant instrument.
8.4	Temperature	647.40	°F	trhin - Plant instrument.
8.5	Enthalpy	#NAME?	Btu/lb	hcrh
8.6	Heat available	#NAME?	Btu/hr	hcrh x CRH

9.0 Hot Reheat

9.1	HRH Flow Rate	#NAME?	lb/hr	HRH = CRH + DSWrh
9.2	Pressure	580.29	psig	prhout - Plant instrument.
9.3	Temperature	1011.31	°F	trhout - Plant instrument.
9.4	Enthalpy	#NAME?	Btu/lb	hhrh
9.5	Heat available	#NAME?	Btu/hr	hhrh x HRH

10.0 TOTAL OUTPUT

10.1	Heat to Main Steam	#NAME?	Btu/hr	HTMS = MS*hms + BD*hcbd - DSW*hdsw - FW*hfw - SB*hsb
10.2	Heat to Reheat Steam	#NAME?	Btu/hr	HTRH = HRH*hhrh- CRH*hcrh- DSWrh*hdswrh
10.3	**TOTAL HEAT OUTPUT**	**#NAME?**	**Btu/hr**	HTMS + HTRH

OUTPUT UNCERTAINTY WORK SHEET NO. 1A

	Measured Parameter (from Data)	Data Form Number	1 Average Value (Item [2] on Data2 form)	2 Standard Deviation (Item [3] on Data2 form)	Bias Sheet No.	3 Total Positive Bias Limit (Item [2] on BIAS form) %	Unit	4 Total Negative Bias Limit (Item [2] on BIAS form) %	Unit	5 No. of Readings (Item [1] on Data2 form)	6 Precision Index (([2]^2)/[5])^1/2	7 Degrees of Freedom [5]-1	8 Percent Change	9 Incremental Change* [8]x[1]/100
a														
b	FEEDWATER FLOW, lb/hr x 1,000	101	4059	8.70	3C	2.85	0.00	2.85	0.00	24	1.78	23	1.00	40.59088
c	FEEDWATER TEMPERATURE, F	102	483.21	0.2865	1D	0.14	3.01	0.14	3.01	24	0.06	23	1.00	4.83
d	FEEDWATER PRESSURE, psig	102A	2616.89	0.5086	2A	0.17	0.00	0.17	0.00	24	0.10	23	1.00	26.17
e														
f	SH-1 SPRAY FLOW, lb/hr x 1,000	103	29	3.26	3D	2.85	0.00	2.85	0.00	24	0.67	23	1.00	0.285592
g	SH-1 SPRAY TEMPERATURE, F	104	404.20	0.1858	1C	0.14	3.01	0.14	3.01	24	0.04	23	1.00	4.04
h	SH-1 SPRAY PRESSURE, psig	104A	2666.89	0.5086	2A	0.17	0.00	0.17	0.00	24	0.10	23	1.00	26.67
i														
j	BLOWDOWN FLOW, lb/hr x 1,000	105	0.0	0.00	3D	2.85	0.00	2.85	0.00	2	0.00	1	1.00	0.00
k	DRUM PRESSURE, psig	106	2586.08	0.80	2A	0.17	0.00	0.17	0.00	24	0.16	23	1.00	25.86
l														
m	MAIN STEAM TEMPERATURE, F	109	1004.8	0.32	3E	2.93	0.00	2.93	0.00	24	0.07	23	1.00	10.05
n	MAIN STEAM PRESSURE, psig	110	2463.26	0.46	2A	0.17	0.00	0.17	0.00	24	0.09	23	1.00	24.63
o														
p	SOOTBLOWING STEAM FLOW, lb/hr x 1,000	107	0.0	0.00	3E	2.93	0.00	2.93	0.00	2	0.00	1	1.00	0.00
q	SOOTBLOWING STEAM TEMPERATURE, F	108	0.00	0.00	1C	0.14	3.01	0.14	3.01	2	0.00	1	1.00	0.00
r	psig	108A	0.00	0.00	2A	0.17	0.00	0.17	0.00	2	0.00	1	1.00	0.00
s														
t	HEATER 1 FW ENTERING TEMPERATURE, F	118	403	0.20	1D	0.14	3.01	0.14	3.01	24	0.04	23	1.00	4.03
u	HEATER 1 FW ENT PRESSURE, psig	118A	2666.89	0.5086	2A	0.17	0.00	0.17	0.00	24	0.10	23	1.00	26.67
v	HEATER 1 FW LEAVING TEMPERATURE, F	119	482.36	0.2189	1D	0.14	3.01	0.14	3.01	24	0.04	23	1.00	4.82
w	HEATER 1 FW LVG PRESSURE, psig	120	2642	0.51	2A	0.17	0.00	0.17	0.00	24	0.10	23	1.00	26.42
x	HEATER 1 EXTRACTION STEAM TEMPERATURE, F	121	644.47	0.3086	1C	0.14	3.01	0.14	3.01	24	0.06	23	1.00	6.44
z	HEATER 1 EXTRACTION STEAM PRESSURE, psig	122	596.18	0.8929	2A	0.17	0.00	0.17	0.00	24	0.18	23	1.00	5.96
y	HEATER 1 DRAIN TEMPERATURE, F	123	418.7	0.22	1D	0.14	3.01	0.14	3.01	24	0.04	23	1.00	4.19
aa	HEATER 1 DRAIN PRESSURE, psig	124	0.00	0.00	2B	0.14	10.00	0.14	10.00	2	0.00	1	1.00	0.00
ab														
ac														
	* The value used for incremental change can be any increment of the average value.													
	The recommended increment is 1.0 percent (0.01 times the average value).													
	If the average value of the measured parameter is zero, use any small incremental change.													
	It is important to note that the incremental change must be in the same units as the average value.													

NAME OF PLANT	ASME PTC 4 MASTER FORM	UNIT NO	
TEST NO.	DATE:	LOAD	
TIME START:	END:	CALC BY	
		DATE	
		SHEET	OF

OUTPUT UNCERTAINTY WORK SHEET NO. 2A

Measured Parameter	10 Recalc Output *	11 Absolute Sensitivity Coefficient ([10]-[20])/[9]	12 Relative Sensitivity Coefficient [11]x[1]/[20]	13 Precision Index of Result Calculation [11]x[6]	14 Overall Deg of Freedom Contribution ([11]x[6])^4/[7]	15 Positive Bias Limit of Result [11]x{([1]x[3A]/100)' + [3B]^2}^1/2	16 Negative Bias Limit of Result [11]x{([1]x[4A]/100)^2 + [4B]^2}^1/2
FEEDWATER FLOW, lb/hr x 1,000	4619.341	0.0011	0.0010	0.0020	0.0000	0.13	0.13
FEEDWATER TEMPERATURE, F	4597.190	-4.5745	-0.4785	-0.2675	0.0002	-14.14	-14.14
FEEDWATER PRESSURE, psig	4619.261	-0.0013	-0.0007	-0.0001	0.0000	-0.01	-0.01
SH-1 SPRAY FLOW, lb/hr x 1,000	4619.295	0.0012	0.0000	0.0008	0.0000	0.00	0.00
SH-1 SPRAY TEMPERATURE, F	4619.172	-0.0303	-0.0026	-0.0011	0.0000	-0.09	-0.09
SH-1 SPRAY PRESSURE, psig	4619.294	0.0000	0.0000	0.0000	0.0000	0.00	0.00
BLOWDOWN FLOW, lb/hr x 1,000	4619.295	0.0000	0.0000	0.0000	0.0000	0.00	0.00
DRUM PRESSURE, psig	4619.295	0.0000	0.0000	0.0000	0.0000	0.00	0.00
MAIN STEAM TEMPERATURE, F	4647.033	2.7607	0.6005	0.1822	0.0000	81.22	81.22
MAIN STEAM PRESSURE, psig	4615.928	-0.1367	-0.0729	-0.0128	0.0000	-0.58	-0.58
SOOTBLOWING STEAM FLOW, lb/hr x 1,000	4619.295	0.0000	0.0000	0.0000	0.0000	0.00	0.00
SOOTBLOWING STEAM TEMPERATURE, F	4619.295	0.0000	0.0000	0.0000	0.0000	0.00	0.00
SOOTBLOWING STEAM PRESSURE, psig	4619.295	0.0000	0.0000	0.0000	0.0000	0.00	0.00
HEATER 1 FW ENTERING TEMPERATURE, F	4657.355	9.4402	0.8239	0.3816	0.0009	28.97	28.97
HEATER 1 FW ENT PRESSURE, psig	4619.469	0.0065	0.0038	0.0007	0.0000	0.03	0.03
HEATER 1 FW LEAVING TEMPERATURE, F	4572.468	-9.7079	-1.0137	-0.4337	0.0015	-30.01	-30.01
HEATER 1 FW LVG PRESSURE, psig	4619.221	-0.0028	-0.0016	-0.0003	0.0000	-0.01	-0.01
HEATER 1 EXTRACTION STEAM TEMPERATURE, F	4630.375	1.7193	0.2399	0.1083	0.0000	5.42	5.42
HEATER 1 EXTRACTION STEAM PRESSURE, psig	4617.995	-0.2181	-0.0281	-0.0397	0.0000	-0.23	-0.23
HEATER 1 DRAIN TEMPERATURE, F	4608.931	-2.4750	-0.2243	-0.1103	0.0000	-7.60	-7.60
HEATER 1 DRAIN PRESSURE, psig	4619.295	0.0000	0.0000	0.0000	0.0000	0.00	0.00
Base Output			from Item [37] on OUTPUT form				SeeUNCERTb2B
Precision Index of Result			([13a]^2+[13b]^2+.....)^1/2				0.4640
Overall Degrees of Freedom			[21]^4/([14a]+[14b]+.....)				0.0027
Student t Value			from Table 5-1 in Code				
Precision Component of Uncertainty			[21]x[23]				
Positive Bias Limit of Result			([15a]^2+[15b]^2+.....)^1/2				8623.0510
Negative Bias Limit of Result			([16a]^2+[16b]^2+.....)^1/2				8623.0510
Positive Total Uncertainty			([24]^2 + [25]^2)^1/2				
Negative Total Uncertainty			([24]^2 + [26]^2)^1/2				

OF PLANT	ASME PTC 4 MASTER FORM		UNIT NO	
NO.		DATE:	LOAD	
START:		END:	CALC BY	
			DATE	
			SHEET	OF

OUTPUT UNCERTAINTY WORK SHEET NO. 1B

	Measured Parameter (from Data2)	Data Form Number	1 Average Value (Item [2] on Data2 form)	2 Standard Deviation (Item [3] on Data2 form)	Bias Sheet No.	3 Total Positiv Bias Limi (Item [2] on BIAS forr %	Unit	4 Total Negative Bias Limit (Item [2] on BIAS form) %	Unit	5 No. of Readings (Item [1] on Data2 form)	6 Precision Index ([2]^2)/[5])^1/2	7 Degrees of Freedom [5]-1	8 Percent Change	9 Incremental Change* [8]x[1]/100
a	REHEATER OUTLET TEMPERATURE, F	111	1011.31	0.62	1C	0.14	0.58	0.14	0.58	24	0.13	23	1.00	10.11
b	REHEATER OUTLET PRESSURE, psig	112	580.29	0.77	2A	0.17	0.00	0.17	0.00	24	0.16	23	1.00	5.80
c														
d	COLD REHEAT ENT ATTEMPERATOR TEMPERATURE, F	113	647.4	0.22	1C	0.14	0.58	0.14	0.58	24	0.04	23	1.00	6.47
e	COLD REHEAT ENT ATTEMPERATOR PRESSURE, psig	114	600.87	0.82	2A	0.17	0.00	0.14	0.58	24	0.17	23	1.00	6.01
f														
g	RH SPRAY WATER FLOW, lb/hr x 1,000	115	0.0	0.00	3D	2.85	0.00	2.85	0.00	24	0.00	23	1.00	0.00
h	RH SPRAY WATER TEMPERATURE, F	116	399.20	0.19	1D	0.14	3.01	0.14	3.01	24	0.04	23	1.00	3.99
i	RH SPRAY WATER PRESSURE, psig	116A	1000.0	0.00	2A	0.17	0.00	0.14	0.58	24	0.00	23	1.00	10.00
j														
k	T/G LEAKAGE FLOW, lb/hr x 1,000	117	0.00	0.00	3E	2.93	0.00	2.93	0.00	24	0.00	23	1.00	0.00
l														
m														
n														
o														
p														
q														
r														
s														
t														
u														
v														
w														
x														
y														
z														
	* The value used for incremental change can be any increment of the average value.													
	The recommended increment is 1.0 percent (0.01 times the average value).													
	parameter is zero, use any small incremental change.													
	It is important to note that the incremental change must be in the same units as the average value.													

NAME OF PLANT	ASME PTC 4 MASTER FORM		UNIT NO	
TEST NO.	DATE:		LOAD	
TIME START:	END:		CALC BY	
			DATE	
			SHEET	OF

OUTPUT UNCERTAINTY WORK SHEET NO. 2B

Measured Parameter	10 Recalc Output *	11 Absolute Sensitivity Coefficient ([10]-[20])/[9]	12 Relative Sensitivity Coefficient [11]x[1]/[20]	13 Precision Index of Result Calculation [11]x[6]	14 Overall Deg of Freedom Contribution ([11]x[6])^4/[7]	15 Positive Bias Limit of Result [11]*{([1]x[3A]/100)^ + [3B]^2}^1/2	16 Negative Bias Limit of Result [11]*{([1]x[4A]/100)^2 + [4B]^2}^1/2
REHEATER OUTLET TEMPERATURE, F	4634.175	1.4714	0.3221	0.1849	0.0001	2.27	2.27
REHEATER OUTLET PRESSURE, psig	4618.849	-0.0768	-0.0096	-0.0121	0.0000	-0.08	-0.08
COLD REHEAT ENT ATTEMPERATOR TEMPERATURE, F	4608.691	-1.6380	-0.2296	-0.0724	0.0000	-1.78	-1.78
COLD REHEAT ENT ATTEMPERATOR PRESSURE, psig	4620.489	0.1988	0.0259	0.0333	0.0000	0.21	0.20
RH SPRAY WATER FLOW, lb/hr x 1,000	4619.295	0.0000	0.0000	0.0000	0.0000	0.00	0.00
RH SPRAY WATER TEMPERATURE, F	4619.295	0.0000	0.0000	0.0000	0.0000	0.00	0.00
RH SPRAY WATER PRESSURE, psig	4619.295	0.0000	0.0000	0.0000	0.0000	0.00	0.00
T/G LEAKAGE FLOW, lb/hr x 1,000	4619.295	0.0000	0.0000	0.0000	0.0000	0.00	0.00
Base Output, MBtu/hr			from Item [37] on OUTPUT form				4619.294679
Precision Index of Result			([13a]^2+[13b]^2+.....)^1/2				0.7104
Overall Degrees of Freedom			[21]^4/([14a]+[14b]+.....)				91.1581
Student t Value			from Table 5-1 in Code				1.985194179
Precision Component of Uncertainty			[21]x[23]				1.410365735
Positive Bias Limit of Result			([15a]^2+[15b]^2+.....)^1/2				92.9055
Negative Bias Limit of Result			([16a]^2+[16b]^2+.....)^1/2				92.9055
Positive Total Uncertainty			([24]^2 + [25]^2)^1/2				92.91617118
Negative Total Uncertainty			([24]^2 + [26]^2)^1/2				92.91616671

OF PLANT	ASME PTC 4 MASTER FORM	UNIT NO	
NO.	DATE:	LOAD	
START:	END:	CALC BY	
		DATE	
		SHEET	OF

EFFICIENCY UNCERTAINTY WORK SHEET NO. 1A

	Measured Parameter (from Data)	Data Form Number	1 Average Value (Item [2] on Data form)	2 Standard Deviation (Item [3] on Data form)	Bias Sheet No.	3 Total Positiv Bias Limi (Item [2] on BIAS forr %	Unit	4 Total Negativ Bias Limit (Item [2] on BIAS form %	Unit	5 No. of Readings (Item [1] on Data form)	6 Precision Index (([2]^2)/[5])^1/2	7 Degrees of Freedom [5]-1	8 Percent Change	9 Incremental Change* [8]x[1]/100
a	OUTPUT		4619.29								1.41	91.16	1.00	46.19
b	BAROMETRIC PRESSURE, in Hg	3	29.87	0.0643	4B	0.00	0.11	0.00	0.11	3	0.04	2	1.00	0.30
c	AMBIENT DRY BULB TEMPERATURE, F	4	98	1.25	1A	0.14	4.01	0.14	4.01	4	0.62	3	1.00	0.97975
d	AMBIENT WET BULB TEMPERATURE, F	5	74.58	0.4031	1A	0.14	4.01	0.14	4.01	4	0.20	3	1.00	0.75
e	%	36	0.20	0.00	INPUT	0	0	0	0	0	0	0	1.00	0.0020
f														
g	FUEL HHV, Btu/lb	1	10944	301.72	6A	2.00	54.00	2.24	54.00	8	106.67	7	1.00	109.435
h	FUEL FLOW, Klb/hr	2	497.65	3.0520	3A	5.10	0.00	5.10	0.00	24	0.62	23	1.00	4.98
i	FUEL CARBON CONTENT, %	15A	60.66	1.75	6B	0.32	0.00	0.32	0.00	8	0.62	7	1.00	0.61
j	FUEL SULFUR CONTENT, %	15C	2.44	0.38	6C	0.11	0.00	0.11	0.00	8	0.13	7	1.00	0.02
k	FUEL HYDROGEN CONTENT, %	15D	4.4	0.14	6D	0.12	0.00	0.12	0.00	8	0.05	7	1.00	0.04
l	FUEL MOISTURE CONTENT, %	15E	13.46	0.39	6E	2.02	0.00	10.20	0.00	8	8.00	7	1.00	0.13
m	FUEL NITROGEN CONTENT, %	15G	1.2	0.04	6D	0.12	0.00	0.12	0.00	8	0.01	7	1.00	0.01
n	FUEL OXYGEN CONTENT, %	15H	6.63	0.30	6D	0.12	0.00	0.12	0.00	8	0.11	7	1.00	0.07
o	FUEL ASH CONTENT, %	15F	11.2	1.67	6D	0.12	0.00	0.12	0.00	8	0.59	7	1.00	0.11
p	FUEL CALCIUM CONTENT, %	15B	0.00	0.00	6D	0.12	0.00	0.12	0.00	9	0.00	8	1.00	0.00
q														
r	FLUE GAS TEMP LVG PRIMARY AIR HEATER, F	7	327.4	1.15	1B	0.14	4.13	0.14	4.13	24	0.24	23	1.00	3.27
s	FLUE GAS TEMP LVG SECONDARY AIR HEATER, F	8	257.32	1.18	1B	0.14	4.13	0.14	4.13	24	0.24	23	1.00	2.57
t	FLUE GAS O2 ENTERING PRIMARY AIR HEATER, F	11	3.93	0.05	5A	0.00	0.15	0.00	0.15	24	0.01	23	1.00	0.04
u	FLUE GAS O2 ENTERING SECONDARY AIR HEATER, F	12	3.98	0.05	5A	0.00	0.15	0.00	0.15	24	0.01	23	1.00	0.04
v	FLUE GAS O2 LEAVING PRIMARY AIR HEATER, F	13	5.6	0.05	5B	0.00	0.15	0.00	0.15	24	0.01	23	1.00	0.06
w	FLUE GAS O2 LEAVING SECONDARY AIR HEATER, F	14	5.93	0.11	5B	0.00	0.15	0.00	0.15	24	0.02	23	1.00	0.06
x	SO2 IN FLUE GAS, (AH INLET) PPM	26	176.14	6.30	8A	0.00	22.91	0.00	22.91	0	0.00	0	1.00	1.76
y	FLUE GAS TEMP ENT PRIMARY AIR HEATER, F	16	619.73	0.55	1B	0.14	4.13	0.14	4.13	24	0.11	23	1.00	6.20
z	FLUE GAS TEMP ENT SECONDARY AIR HEATER, F	17	637	1.5547357	1B	0.14	4.13	0.14	4.13	24	0.3173591	23	1	6.367018
aa														
	* The value used for incremental change can be any increment of the average value.													
	The recommended increment is 1.0 percent (0.01 times the average value).													
	parameter is zero, use any small incremental change.													
	It is important to note that the incremental change must be in the same units as the average value.													

NAME OF PLANT	ASME PTC 4 MASTER FORM	UNIT NO	
TEST NO.	DATE:	LOAD	
TIME START:	END:	CALC BY	
		DATE	
		SHEET	OF

EFFICIENCY UNCERTAINTY WORK SHEET NO. 2A

	Measured Parameter	10 Recalc Efficiency *	11 Absolute Sensitivity Coefficient ([10]-[20])/[9]	12 Relative Sensitivity Coefficient [11]x[1]/[20]	13 Precision Index of Result Calculation [11]x[6]	14 Overall Deg of Freedom Contribution ([11]x[6])^4/[7]	15 Positive Bias Limit of Result [11]x{([1]x[3A]/100) + [3B]^2}^1/2	16 Negative Bias Limit of Result [11]x{([1]x[4A]/100)^2 + [4B]^2}^1/2
a	OUTPUT	85.318	-0.0901	-4.6531	-0.1271	0.0000	0.00	0.00
b	BAROMETRIC PRESSURE, in Hg	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
c	AMBIENT DRY BULB TEMPERATURE, F	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
d	AMBIENT WET BULB TEMPERATURE, F	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
e	SURFACE RADIATION AND CONVECTION, %	89.480	-1.0000	-0.0022	0.0000	0.0000	0.00	0.00
f								
g	FUEL HHV, Btu/lb	89.585	0.0009	0.1157	0.1009	0.0000	0.21	0.24
h	FUEL FLOW, Klb/hr	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
i	FUEL CARBON CONTENT, %	89.440	-0.0699	-0.0474	-0.0432	0.0000	-0.01	-0.01
j	FUEL SULFUR CONTENT, %	89.496	0.5813	0.0159	0.0782	0.0000	0.00	0.00
k	FUEL HYDROGEN CONTENT, %	89.435	-1.0644	-0.0528	-0.0527	0.0000	-0.01	-0.01
l	FUEL MOISTURE CONTENT, %	89.468	-0.1010	-0.0152	-0.8078	0.0608	-0.03	-0.14
m	FUEL NITROGEN CONTENT, %	89.482	-0.0006	0.0000	0.0000	0.0000	0.00	0.00
n	FUEL OXYGEN CONTENT, %	89.482	0.0029	0.0002	0.0003	0.0000	0.00	0.00
o	FUEL ASH CONTENT, %	89.437	-0.4016	-0.0502	-0.2367	0.0004	-0.01	-0.01
p	FUEL CALCIUM CONTENT, %	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
q								
r	FLUE GAS TEMP LVG PRIMARY AIR HEATER, F	89.394	-0.0269	-0.0984	-0.0063	0.0000	-0.11	-0.11
s	FLUE GAS TEMP LVG SECONDARY AIR HEATER, F	89.477	-0.0019	-0.0055	-0.0005	0.0000	-0.01	-0.01
t	FLUE GAS O2 ENTERING PRIMARY AIR HEATER, F	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
u	FLUE GAS O2 ENTERING SECONDARY AIR HEATER, F	85.279	-105.5475	-4.6964	-1.1283	0.0705	-15.83	-15.83
v	FLUE GAS O2 LEAVING PRIMARY AIR HEATER, F	89.482	0.0003	0.0000	0.0000	0.0000	0.00	0.00
w	FLUE GAS O2 LEAVING SECONDARY AIR HEATER, F	85.271	-71.0266	-4.7063	-1.5244	0.2348	-10.65	-10.65
x	SO2 IN FLUE GAS, (AH INLET) PPM	85.278	-2.3866	-4.6978	0.0000	0.0000	-54.68	-54.68
y	FLUE GAS TEMP ENT PRIMARY AIR HEATER, F	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
z	FLUE GAS TEMP ENT SECONDARY AIR HEATER, F	85.27865	-0.6602	-4.6973	-0.2095	0.0001	-2.79	-2.79
aa								
20	Base Efficiency			from Item [100] on EFFb form				See UNCERT2C
21	Precision Index of Result			([13a]^2+[13b]^2+.....)^1/2				4.3865
22	Overall Degrees of Freedom			[21]^4/([14a]+[14b]+.....)				0.3666
23	Student t Value			from Table 5-1 in Code				
24	Precision Component of Uncertainty			[21]x[23]				
25	Positive Bias Limit of Result			([15a]^2+[15b]^2+.....)^1/2				3362.2527
26	Negative Bias Limit of Result			([16a]^2+[16b]^2+.....)^1/2				3362.2819
27	Positive Total Uncertainty			([24]^2 + [25]^2)^1/2				
28	Negative Total Uncertainty			([24]^2 + [26]^2)^1/2				

NAME OF PLANT	ASME PTC 4 MASTER FORM	UNIT NO	
TEST NO.	DATE:	LOAD	
TIME START:	END:	CALC BY	
		DATE	
		SHEET	OF

EFFICIENCY UNCERTAINTY WORK SHEET NO. 1B

			1	2		3 Total Positiv		4 Total Negativ		5	6	7	8	9
	Measured		Average	Standard		Bias Limi		Bias Limit		No. of	Precision	Degrees		Incremental
	Parameter	Data Form	Value	Deviation	Bias	(Item [2] on		(Item [2] on		Readings	Index	of	Percent	Change*
	(from Data2)	Number	(Item [2] on	(Item [3] on	Sheet	BIAS forr		BIAS forn		(Item [1] on	(([2]^2)/[5])^1/2	Freedom	Change	[8]x[1]/100
			Data2 form)	Data form)	No.	%	Unit	%	Unit	Data2 form)		[5]-1		
a	FEEDWATER FLOW, lb/hr x 1,000	101	4059088	8.6995	3C	2.85	0.00	2.85	0.00	24	1.78	23	1.00	40590.88
b	FEEDWATER TEMPERATURE, F	102	483	0.29	1D	0.14	3.01	0.14	3.01	24	0.06	23	1.00	4.832083
c	FEEDWATER PRESSURE, psig	102A	2616.89	0.5086	2A	0.17	0.00	0.17	0.00	24	0.10	23	1.00	26.17
d	SH-1 SPRAY FLOW, lb/hr x 1,000	103	28559.18	3.2581	3D	2.85	0.00	2.85	0.00	24	0.67	23	1.00	285.59
e	SH-1 SPRAY TEMPERATURE, F	104	404	0.19	1D	0.14	3.01	0.14	3.01	24	0.04	23	1.00	4.04195
f	SH-1 SPRAY PRESSURE, psig	104A	2666.89	0.5086	2A	0.17	0.00	0.17	0.00	24	0.10	23	1.00	26.67
g	BLOWDOWN FLOW, lb/hr x 1,000	105	0.00	0.0000	3E	2.93	0.00	2.93	0.00	2	0.00	1	1.00	0.00
h	DRUM PRESSURE, psig	106	2586.1	0.80	2A	0.17	0.00	0.17	0.00	24	0.16	23	1.00	25.86
i	MAIN STEAM TEMPERATURE, F	109	1004.76	0.32	1C	0.14	0.58	0.14	0.58	24	0.07	23	1.00	10.05
j	MAIN STEAM PRESSURE, psig	110	2463.26	0.46	2A	0.17	0.00	0.17	0.00	24	0.09	23	1.00	24.63
k	REHEATER OUTLET TEMPERATURE, F	111	1011.3	0.62	1C	0.14	0.58	0.14	0.58	24	0.13	23	1.00	10.11
l	REHEATER OUTLET PRESSURE, psig	112	580.29	0.77	2A	0.17	0.00	0.17	0.00	24	0.16	23	1.00	5.80
m	COLD REHEAT ENT ATTEMPERATOR TEMPERATURE, F	113	647.40	0.22	1C	0.141	0.58	0.14	0.58	24	0.04	23	1.00	6.47
n	COLD REHEAT ENT ATTEMPERATOR PRESSURE, psig	114	600.87	0.82	2A	0.17	0.00	0.17	0.00	24	0.17	23	1.00	6.01
o	RH SPRAY WATER FLOW, lb/hr x 1,000	115	0.0	0.00	3D	2.85	0.00	2.85	0.00	24	0.00	23	1.00	0.00
p	RH SPRAY WATER TEMPERATURE, F	116	399.20	0.19	1D	0.14	3.01	0.14	3.01	24	0.04	23	1.00	3.99
q	RH SPRAY WATER PRESSURE, psig	116A	1000.00	0.00	2A	0.17	0.00	0.17	0.00	24	0.00	23	1.00	10.00
r														
s														
t	TOTAL SA FLOW, KLB/HR	6	1000.00	0.00	3H	5.12	0.00	5.12	0.00	2	0.00	1	1.00	10.00
u	COMB AIR TEMP LVG PRIMARY AIR HEATER, F	18	541	0.8945791	1A	0.14	4.01	0.14	4.01	24	0.1826052	23	1	5.406875
v	COMB AIR TEMP LVG SECONDARY AIR HEATER, F	19	581	0.5262403	1A	0.14	4.01	0.14	4.01	24	0.1074183	23	1	5.807323
ad	COMB AIR FLOW ENT PRIMARY AIR HEATER, LB/HR	9A	133.89	0.83	3H	5.12	0.00	5.12	0.00	24	0.17	23	1.00	1.34
x	COMB AIR TEMP ENT PRIMARY AIR HEATER, F	9B	133.89	0.83	1A	0.14	4.01	0.14	4.01	24	0.17	23	1.00	1.34
y	COMB AIR FLOW BYPASSING PRIMARY AIR HEATER, LB/HR	10A	114.66	2.70	3H	5.12	0.00	5.12	0.00	24	0.55	23	1.00	1.15
z	COMB AIR TEMP ENT SECONDARY AIR HEATER, F	10B	114.7	2.70	1A	0.14	4.01	0.14	4.01	24	0.55	23	1.00	1.15
aa														
	* The value used for incremental change can be any increment of the average value.													
	The recommended increment is 1.0 percent (0.01 times the average value).													
	parameter is zero, use any small incremental change.													
	It is important to note that the incremental change must be in the same units as the average value.													
NAME OF PLANT			ASME PTC 4 MASTER FORM										UNIT NO	
TEST NO.			DATE:										LOAD	
TIME START:			END:										CALC BY	
													DATE	
													SHEET	OF

EFFICIENCY UNCERTAINTY WORK SHEET NO. 2B

	Measured Parameter	10 Recalc Efficiency *	11 Absolute Sensitivity Coefficient ([10]-[20])/[9]	12 Relative Sensitivity Coefficient [11]x[1]/[20]	13 Precision Index of Result Calculation [11]x[6]	14 Overall Deg of Freedom Contribution ([11]x[6])^4/[7]	15 Positive Bias Limit of Result [11]x{([1]x[3A]/100) + [3B]^2}^1/2	16 Negative Bias Limit of Result [11]x{([1]x[4A]/100)^2 + [4B]^2}^1/2
a	FEEDWATER FLOW, lb/hr x 1,000	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
b	FEEDWATER TEMPERATURE, F	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
c	FEEDWATER PRESSURE, psig	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
d	SH-1 SPRAY FLOW, lb/hr x 1,000	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
e	SH-1 SPRAY TEMPERATURE, F	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
f	SH-1 SPRAY PRESSURE, psig	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
g	BLOWDOWN FLOW, lb/hr x 1,000	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
h	DRUM PRESSURE, psig	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
i	MAIN STEAM TEMPERATURE, F	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
j	MAIN STEAM PRESSURE, psig	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
k	REHEATER OUTLET TEMPERATURE, F	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
l	REHEATER OUTLET PRESSURE, psig	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
m	COLD REHEAT ENT ATTEMPERATOR TEMPERATURE, F	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
n	COLD REHEAT ENT ATTEMPERATOR PRESSURE, psig	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
o	RH SPRAY WATER FLOW, lb/hr x 1,000	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
p	RH SPRAY WATER TEMPERATURE, F	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
q	RH SPRAY WATER PRESSURE, psig	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
r								
s								
t	TOTAL SA FLOW, KLB/HR	89.298	-0.0184	-0.2059	0.0000	0.0000	-0.94	-0.94
u	COMB AIR TEMP LVG PRIMARY AIR HEATER, F	85.268	-0.7793	-4.7091	-0.1423	0.0000	-3.1824	-3.182436753
v	COMB AIR TEMP LVG SECONDARY AIR HEATER, F	85.279	-0.7238	-4.6973	-0.0777	0.0000	-2.9635	-2.96349125
ad	COMB AIR FLOW ENT PRIMARY AIR HEATER, LB/HR	89.484	0.0013	0.0019	0.0002	0.0000	0.01	0.01
x	COMB AIR TEMP ENT PRIMARY AIR HEATER, F	89.510	0.0208	0.0311	0.0035	0.0000	0.08	0.08
y	COMB AIR FLOW BYPASSING PRIMARY AIR HEATER, LB/HR	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
z	COMB AIR TEMP ENT SECONDARY AIR HEATER, F	89.484	0.0015	0.0019	0.0008	0.0000	0.01	0.01
aa								
20	Base Efficiency			from Item [100] on EFFb form				See UNCERT2C
21	Precision Index of Result			([13a]^2+[13b]^2+.....)^1/2				0.0263
22	Overall Degrees of Freedom			[21]^4/([14a]+[14b]+.....)				0.0000
23	Student t Value			from Table 5-1 in Code				
24	Precision Component of Uncertainty			[21]x[23]				
25	Positive Bias Limit of Result			([15a]^2+[15b]^2+.....)^1/2				19.8083
26	Negative Bias Limit of Result			([16a]^2+[16b]^2+.....)^1/2				19.8083
27	Positive Total Uncertainty			([24]^2 + [25]^2)^1/2				
28	Negative Total Uncertainty			([24]^2 + [26]^2)^1/2				

NAME OF PLANT	ASME PTC 4 MASTER FORM	UNIT NO	
TEST NO.	DATE:	LOAD	
TIME START:	END:	CALC BY	
		DATE	
		SHEET	OF

Building Community

EFFICIENCY UNCERTAINTY WORK SHEET NO. 1C

			1	2		3 Total Positiv		4 Total Negativ		5	6	7	8	9
	Measured		Average	Standard		Bias Limi		Bias Limit		No. of	Precision	Degrees		Incremental
	Parameter	Data Form	Value	Deviation	Bias	(Item [2] on		(Item [2] on		Readings	Index	of	Percent	Change*
	(from Data)	Number	(Item [2] on	(Item [3] on	Sheet	BIAS forr		BIAS forn		(Item [1] on	(([2]^2)/[5])^1/2	Freedom	Change	[8]x[1]/100
			Data form)	Data form)	No.	%	Unit	%	Unit	Data form)		[5]-1		
a	SEAL POT BLOWER AIR FLOW, LB/HR	38	115	2.7021	3H	5.12	0.00	5.12	0.00	24	0.55	23	1.00	1.15
b	SEAL POT BLOWER EXIT AIR TEMP, F	40	115	2.70	1A	0.14	4.01	0.14	4.01	24	0.55	23	1.00	1.146643
c	INTREX BLOWER AIR FLOW, LB/HR	37	133.89	0.8336	3H	5.12	0.00	5.12	0.00	24	0.17	23	1.00	1.34
d	INTREX BLOWER EXIT AIR TEMP, F	39	133.89	0.8336	1A	0.14	4.01	0.14	4.01	24	0.17	23	1.00	1.34
e														
f	FLY ASH FLOW RATE, KLB/HR	20	0.00	0.0000	3G	7.00	0.00	7.00	0.00	2	0.00	1	1.00	0.00
g	ORGANIC CARBON IN FLY ASH, %	22A	11.66	1.13	7A	5.01	0.00	5.01	0.00	8	0.40	7	1.00	0.12
h	INORGANIC CARBON IN FLY ASH, %	22B	0.15	0.17	7A	5.01	0.00	5.01	0.00	8	0.06	7	1.00	0.00
i	CALCIUM IN FLY ASH, %	22C	11.7	1.13	7A	5.01	0.00	5.01	0.00	8	0.40	7	1.00	0.12
j	CARBONATE IN FLY ASH AS CO2, %	22D	0.15	0.17	7A	5.01	0.00	5.01	0.00	8	0.06	7	1.00	0.00
k														
l	BOTTOM ASH INORGANIC CARBON CONTENT, %	23B	0.15	0.17	7A	5.01	0.00	5.01	0.00	8	0.06	7	1.00	0.00
m	BOTTOM ASH TEMPERATURE, F	21	1499.19	10.82	1B	0.14	4.13	0.14	4.13	24	2.21	23	1.00	14.99
n	BOTTOM ASH ORGANIC CARBON CONTENT, %	23A	0.15	0.1687	7A	5.01	0.00	5.01	0.00	8	0.06	7	1.00	0.00
o	BOTTOM ASH CALCIUM CONTENT, %	23C	12	1.125902	7A	5.01	0.00	5.01	0.00	8	0.3980665	7	1	0.116638
p	BOTTOM ASH CARBONATE AS CO2, %	23D	0	0.1686872	7A	5.01	0.00	5.01	0.00	8	0.0596399	7	1	0.001463
q														
r	LIMESTONE FLOW, lb/hr	25	100.5	0.62	3B	7.00	0.00	7.00	0.00	24	0.13	23	1.00	1.01
s	CaCO3 IN LIMESTONE, % mass	28	94.03	0.75	9A	2.00	0.16	2.00	0.16	0	0.00	0	1.00	0.94
t	Ca(OH)2 IN LIMESTONE, % mass	29	0.00	0.00	9A	2.00	0.16	2.00	0.16	0	0.00	0	1.00	0.00
u	MgCO3 IN LIMESTONE, % mass	30	1.3	0.11	9B	2.00	0.11	2.00	0.11	0	0.00	0	1.00	0.01
v	LIMESTONE CARBONATE CONVERSION FRACTION, %	31	95.00	0.00	9B	2.00	0.11	2.00	0.11	0	0.00	0	1.00	0.95
w	MOISTURE IN LIMESTONE, % mass	32	0.1	0.06	9C	5.39	0.00	5.39	0.00	0	0.00	0	1.00	0.00
x	INERT MATERIAL IN LIMESTONE, % mass	33	4.65	0.71	9D	14.28	0.00	10.20	0.00	0	0.00	0	1.00	0.05
y														
z														
aa														
	* The value used for incremental change can be any increment of the average value.													
	The recommended increment is 1.0 percent (0.01 times the average value).													
	parameter is zero, use any small incremental change.													
	It is important to note that the incremental change must be in the same units as the average value.													
NAME OF PLANT			ASME PTC 4 MASTER FORM										UNIT NO	
TEST NO.			DATE:										LOAD	
TIME START:			END:										CALC BY	
													DATE	
													SHEET	OF

EFFICIENCY UNCERTAINTY WORK SHEET NO. 2C

	Measured Parameter	10 Recalc Efficiency *	11 Absolute Sensitivity Coefficient ([10]-[20])/[9]	12 Relative Sensitivity Coefficient [11]x[1]/[20]	13 Precision Index of Result Calculation [11]x[6]	14 Overall Deg of Freedom Contribution ([11]x[6])^4/[7]	15 Positive Bias Limit of Result [11]x{([1]x[3A]/100) + [3B]^2}^1/2	16 Negative Bias Limit of Result [11]x{([1]x[4A]/100)^2 + [4B]^2}^1/2
a	SEAL POT BLOWER AIR FLOW, LB/HR	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
b	SEAL POT BLOWER EXIT AIR TEMP, F	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
c	INTREX BLOWER AIR FLOW, LB/HR	89.484	0.0013	0.0019	0.0002	0.0000	0.01	0.01
d	INTREX BLOWER EXIT AIR TEMP, F	89.494	0.0089	0.0133	0.0015	0.0000	0.04	0.04
e								
f	FLY ASH FLOW RATE, KLB/HR	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
g	ORGANIC CARBON IN FLY ASH, %	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
h	INORGANIC CARBON IN FLY ASH, %	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
i	CALCIUM IN FLY ASH, %	89.476	-0.0544	-0.0071	-0.0217	0.0000	-0.03	-0.03
j	CARBONATE IN FLY ASH AS CO2, %	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
k								
l	BOTTOM ASH INORGANIC CARBON CONTENT, %	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
m	BOTTOM ASH TEMPERATURE, F	89.476	-0.0004	-0.0069	-0.0009	0.0000	0.00	0.00
n	BOTTOM ASH ORGANIC CARBON CONTENT, %	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
o	BOTTOM ASH CALCIUM CONTENT, %	89.445	-0.3163	-0.0412	-0.1259	0.0000	-0.18	-0.18
p	BOTTOM ASH CARBONATE AS CO2, %	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
q								
r	LIMESTONE FLOW, lb/hr	89.482	0.0000	0.0000	0.0000	0.0000	0.00	0.00
s	CaCO3 IN LIMESTONE, % mass	89.483	0.0015	0.0016	0.0000	0.0000	0.00	0.00
t	Ca(OH)2 IN LIMESTONE, % mass	85.279	0.0000	0.0000	0.0000	0.0000	0.00	0.00
u	MgCO3 IN LIMESTONE, % mass	89.482	-0.0169	-0.0002	0.0000	0.0000	0.00	0.00
v	LIMESTONE CARBONATE CONVERSION FRACTION, %	85.279	-4.4245	-4.6973	0.0000	0.0000	-8.42	-8.42
w	MOISTURE IN LIMESTONE, % mass	89.482	-0.0066	0.0000	0.0000	0.0000	0.00	0.00
x	INERT MATERIAL IN LIMESTONE, % mass	89.481	-0.0263	-0.0014	0.0000	0.0000	-0.02	-0.01
y								
z								
aa								
20	Base Efficiency			from Item [100] on EFFb form				89.48189153
21	Precision Index of Result			([13a]^2+[13b]^2+.....)^1/2				2.1045
22	Overall Degrees of Freedom			[21]^4/([14a]+[14b]+.....)				53.4967
23	Student t Value			from Table 5-1 in Code				2.00422994
24	Precision Component of Uncertainty			[21]x[23]				4.217993169
25	Positive Bias Limit of Result			([15a]^2+[15b]^2+.....)^1/2				58.7623
26	Negative Bias Limit of Result			([16a]^2+[16b]^2+.....)^1/2				58.7625
27	Positive Total Uncertainty			([24]^2 + [25]^2)^1/2				58.9134536
28	Negative Total Uncertainty			([24]^2 + [26]^2)^1/2				58.91369995

NAME OF PLANT	ASME PTC 4 MASTER FORM	UNIT NO	
TEST NO.	DATE:	LOAD	
TIME START:	END:	CALC BY	
		DATE	
		SHEET	OF

Attachment T – Correction Curves

Attachment U – Abbreviation List

Following is a definition of abbreviations used in this report. Note that at their first use, these terms are fully defined in the text of the report, followed by the abbreviation in the parenthesis. Subsequent references use the abbreviation only.

Abbreviation	Definition
A.F.	As-Fired
AQCS	Air Quality Control System
BA	Bed Ash
BOP	Balance of Plant
btu	British Thermal Unit
C	Coal
$CaCO_3$	wt. fraction $CaCO_3$ in limestone
Ca:S	Calcium to Sulfur Ration
CaO	Lime
C_b	Pounds of carbon per pound of "as-fired" fuel
CEM	Continuous Emissions Monitoring
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DCS	Distributed Control System
DOE	Department of Energy
F	Fluorine or Degrees Farenheit
FA	Fly ash
FF	Fabric Filter
gpm	gallons per minute
gr/acf	grains per actual cubic foot
gr/dscf	grains per dry standard cubic foot
$h_{\#1DRN}$	Enthalpy of drain from #1 heater

$h_{\#1INFW}$	BFW enthalpy at heater #1 inlet
$h_{\#1OUTFW}$	BFW enthalpy at heater #1 outlet
H_{EXTR1}	Enthalpy of extraction to #1 heater
Hg	Mercury
HHV	Higher Heating Value
HP	High-Pressure
H_{CRH}	Cold reheat steam enthalpy at the boiler outlet, Btu/lb
h_{FW}	Feedwater enthalpy entering the economizer, Btu/lb
H_{HRH}	Hot reheat steam enthalpy at the boiler outlet, Btu/lb
H_{MS}	Main steam enthalpy at the boiler outlet, Btu/lb
L	Lime
lb/hr	Pounds per hour
lb/MMBtu	pounds per million Btu
LS	Limestone
MBtu	Million Btu
MCR	Maximum Continuous Rating
$MgCO_3$	wt. fraction $MgCO_3$ in limestone
MU	Measurement Uncertainty
MW_X	Molecular weight of respective elements
NGS	Northside Generating Station
NH_3	Ammonia
NO_x	Oxides of Nitrogen
NS	Northside
Pb	Lead
PC	Petroleum Coke
pcf	pounds per cubic foot
Pitt 8	Pittsburgh 8

PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
ppm	parts per million
ppmdv	Pounds per million, dry volume
psia	Pounds per square inch pressure absolute
psig	pounds per square inch pressure gauge
PTC	Power Test Code
RH	Reheat
S $Capture_{(AQCS)}$	Sulfur capture by the AQCS, %
SDA	Spray Dryer Absorber
S_f	Wt. fraction of sulfur in fuel, as-fired
SH	Superheat
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
$SO_{2(inlet)}$	SO_2 in the AQCS inlet (lb/MBtu)
$SO_{2(stack)}$	SO_2 in the stack (lb/MBtu)
SO_3	Sulfur Trioxide
TG	Turbine Generator
tph	tons per hour
VOC	Volatile Organic Carbon
W_l	Limestone feed rate (lb/hr)
W_{EXTR1}	Extraction flow to heater #1
W_{fe}	Fuel feed rate (lb/hr)
W_{FWH}	feedwater flow at heaters
W_{MS}	Main steam flow, lb/hr
W_{RH}	Reheat steam flow, lb/hr
wt %	weight percentage

JEA Tag Number Conventions are as follows:

AA-BB-CC-xxx

AA designates GEMS Group/System, as follows:

BK = Boiler Vent and Drains
QF = Feedwater Flow
SE = Reheat Piping
SH = Reheat Superheating
SI = Secondary Superheating
SJ = Main Street Piping

BB designates major equipment codes, as follows:

12 = Control Valve
14 = Manual Valve
34 = Instrument

CC designates instrument type, as follows:

FT = Flow transmitter
FI = Flow indicator
TE = Temperature element

xxx designates numerical sequence number